Corrosion

IN THIS ISSUE:

FOCUS ON PLASTICS
in Process Equipment

Tetrafluoroethylene-Lined Pipe Has Lower Installation Cost 9

Applying Reinforced Plastics In Corrosive Environments 14

Laboratory Screening Tests of Sprayed Linings 26

Design Considerations Applicable to Glass-Reinforced Plastic Pipe 33

High Temperature Testing of Polyester Castings and Laminates 45

Turn to Page 49 for Other Items on Plastics Applications in Process Field

Problems in Use of Dense Salt Solutions as Packer Fluids..... **91**

Stress-Corrosion Cracking of Oil-Country Tubular Goods..... **95**

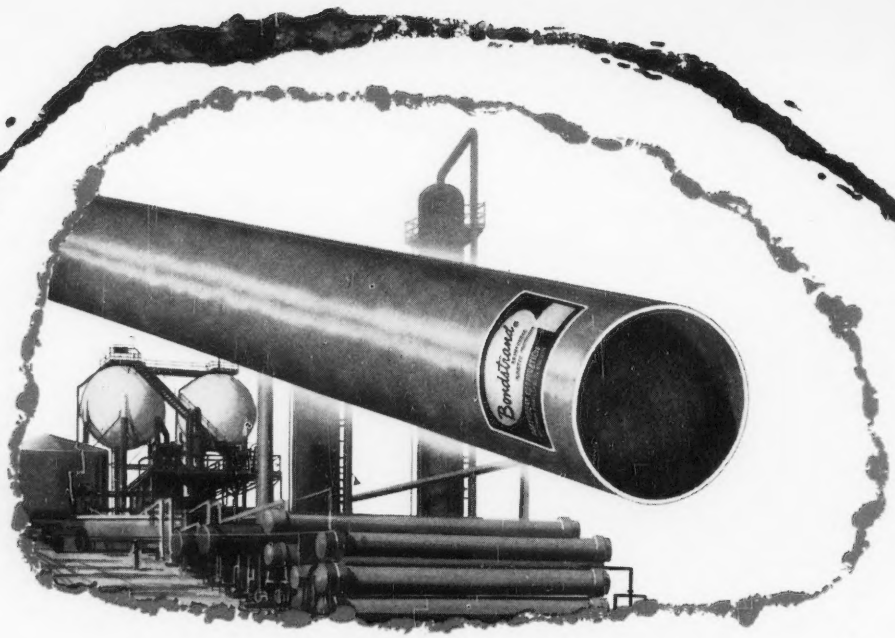
New Developments in Utility Corrosion Mitigation..... **99**

Protective Jackets for Lead and Aluminum Sheathed Cable.....**119**

Corrosion Testing of Zircaloy-Base Fuel Alloys.....**137**

Also: Turn to Page 40 for Table of Plastics Trade Names, Generic Terms and Manufacturers' Names

Complete Contents on Pages 4 and 5



BONDSTRAND®

An imaginative solution to your piping problems

From Missile Research...
A new product for process piping

- Twice as strong as steel
- 1/4 the weight of steel
- Inherently resistant to chemicals which attack stainless steel

Bondstrand is a corrosion-resistant, high strength, rigid pipe made of glass filaments bonded in chemically inert synthetic resins. It is capable of withstanding high pressure and the corrosive attack of many salt, acid, and alkaline solutions. The outside surface is equally resistant because the pipe is made entirely of corrosion-proof materials. No painting or maintenance is necessary.

Bondstrand's light weight and ease of assembly can save up to 50% of installation costs. Actual cost records of typical applications prove that the total installed cost averaged only 1.3 times that of carbon steel pipe. By eliminating the corrosion problem and down time for replacement or repair, Bondstrand saves many times its slightly higher initial cost.

Bondstrand is now available in sizes from 2" through 8" with all necessary couplings and fittings. Larger sizes available on special order.

Write for bulletin containing complete data, including physical properties, chemical resistance, flow rates, and other design information.

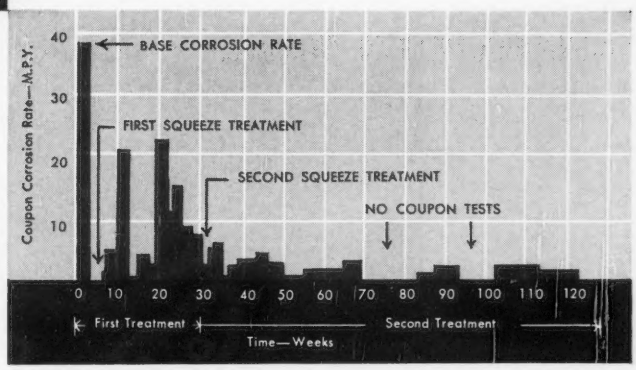
Amercoat® CORPORATION 125

A Subsidiary of American Pipe and Construction Co.

Dept. GK, 4809 Firestone Blvd., South Gate, California

921 Pitner Ave., Evanston, Ill. • 360 Carnegie Ave., Kenilworth, N.J. • 111 Colgate, Buffalo, N.Y. • 2404 Dennis St., Jacksonville, Fla. • 6530 Supply Row, Houston, Tex.

another
TRETOLITE SERVICE
report



Corrosion history of a West Texas well, showing coupon corrosion rate with time

KONTOL *puts the squeeze on corrosion*

Results at a West Texas well show why the KONTOL* Corrosion Inhibitor squeeze technique is rapidly gaining favor with producers everywhere. Located in Crane County, this well is completed in San Andres pay at 3,500 feet. Production rate is 70 bbl. per day, with just a trace of water. It was decided to try KONTOL inhibitor squeeze after coupon testing showed a corrosion rate of approximately 39 m.p.y., and rods were beginning to pit.

KONTOL *treating is simple*

Inhibitor squeeze treating began by pumping a mixture of 30 gallons of KONTOL dispersed in 100 bbl. of crude oil into the formation through the casing-tubing annulus. This was followed by a 100 bbl. crude oil overflush. Surface pressure was approximately 1,000 psi during the squeeze. Following this treatment, the well was closed for 20 hours.

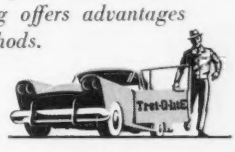
KONTOL *results are positive*

During the first five months following treatment, the corrosion rate varied from a high of 21 m.p.y. to a low of 0.5 m.p.y. For 11 weeks of this period the rate was below 5.0 m.p.y. No equipment failures due to corrosion were reported during the five-month period.

KONTOL *protection is long-lasting*

Six months after original squeeze treatment the corrosion rate was still satisfactory, but it was decided to resqueeze the well to make certain of uninterrupted protection. During the following 90 weeks, coupon tests showed a corrosion rate that averaged 2.0–3.0 m.p.y.—proof of KONTOL's enduring effectiveness.

Ask the Man in the Red Car to explain how KONTOL *Corrosion Inhibitor squeeze treating offers advantages over conventional batchtreating methods. Let him prove why* KONTOL *can be applied more easily and economically, with lasting results.*



*Registered trademark, Petrolite Corporation

KF-60-2

PETROLITE
CORPORATION

TRETOLITE COMPANY
DIVISIONS
369 Marshall Avenue, Saint Louis 19, Missouri
5515 Telegraph Road, Los Angeles 22, California

SUBSIDIARY AND AFFILIATED COMPANIES
CANADA, Edmonton, Alberta • ENGLAND, London
GERMANY, Frankfurt, a. M. • VENEZUELA, Caracas

REPRESENTATIVES
ARGENTINA, Buenos Aires • BRAZIL, Rio de Janeiro • COLOMBIA, Bogota
ITALY, Rome • JAPAN, Tokyo • KUWAIT, Kuwait • MEXICO, Mexico, D. F.
NETHERLANDS, The Hague • PERU, Talara • TRINIDAD, Port of Spain

Keep your
crews busy
all year 'round

with **CARBO ZINC 11***

the all-weather maintenance coating

Most maintenance paints cannot be applied below 40° F. Not so with Carbo Zinc 11 . . . *the only protective coating that can be applied outdoors in cold weather.* Paint *anytime*, 12 months of the year. indoors or out . . . keeping a *smaller* crew busy full time. You still get protection far superior to standard maintenance paints.

- a zinc-filled inorganic protective coating
- water insoluble 20 minutes after applying
- fast drying, long-lasting galvanic protection for steel
- apply in humidity up to 95%, temperatures from –20° F. to 150° F.
- excellent resistance to water, coastal environment, brine, humidity, solvents

Use Carbo Zinc 11 without topcoat, or as primer with vinyl, Hypalon, epoxy, or inorganic topcoat. Resists undercutting and subfilm corrosion. Low material, application and maintenance costs.

Write for information, technical data, uses and samples. Also, see our catalog in CEC, pages 911-914.

6011

*Patent applied for

carboline COMPANY

32-A Hanley Industrial Ct. St. Louis 17, Mo.

Sales engineers in principal cities. Consult your telephone directory.

MAINTENANCE
COATINGS
WITH EXPERIENCE

This Month in Corrosion Control . . .

FLUOROCARBON-LINED piping often can be installed at lower cost than glass-lined, case histories related on Page 9 indicate.

DESIGN CONSIDERATIONS are important in successful installation of reinforced plastics. Detailed information on correct calculations, design and installation procedures is given beginning on Page 14.

SPRAYED LININGS can be screened successfully in the laboratory, thereby preventing loss and damage resulting from misapplication. See Page 26 for a report on how one chemical company does it.

PLASTIC PIPE DESIGN information that you can use in correctly employing glass reinforced plastic pipe is given by an engineer with long experience. Thermoplastic and thermosetting pipes are rated versus various corrosives, temperatures, pressures and other factors. See Page 33.

POLYESTER materials were tested against various corrosives at 210 F for three and six months with some interesting results detailed on Pages 44-45. Detailed tabulated data are given.

INCONEL is corroded selectively in a fused salt bath by a combination of the Kirkendall effect and electrochemical factors it is reported in an article beginning on Page 89.

DENSE SALT SOLUTIONS used as packer fluids in the completion of oil wells involve hazards of corrosion and stress corrosion cracking. Data on extensive tests of several such solutions are given beginning on Page 91.

HIGH STRENGTH oil country tubular goods are failing catastrophically from stress-corrosion cracking in spite of improved fabrication and handling practices. It frequently is impossible to detect the agency responsible for these failures an article beginning on Page 95 points out.

UTILITY CORROSION mitigation measures including different types of inert and galvanic anodes, deep ground beds, concrete coatings, rectifier protection against current surges and others are considered beginning on Page 99.

FERRIC CHLORIDE in low concentrations causes rapid corrosion of mild steel at 316 C. Chloride-bearing slurries act in much the same way. Data on laboratory tests are given beginning on Page 109.

API TUBING steels failed from stress corrosion cracking when exposed to hot sodium nitrate solutions at various concentrations. Laboratory data on these tests and others including calcium chloride and sodium nitrate solutions are given beginning on Page 113.

LEAD AND ALUMINUM sheathed cable protection practices of 32 electric utility companies are given in considerable detail in an NACE technical committee report beginning on Page 119. Anyone concerned with jacketed cables will find these data revealing, especially corrosion engineers who will note that corrosion protection is the reason for using these coverings in a majority of cases.

NUCLEAR POWER PLANT boilers are susceptible to corrosion from sludge which accumulates at the surface of the horizontal tube sheet. Tests of several materials showed Inconel to be most resistant. Turn to Page 127.

TYPE 309 alloy steel operated for six weeks in flue gas at 1600-2100 F was seriously corroded, apparently as a result of contaminants fluxing the hot metal surfaces. A discussion of this refinery furnace corrosion problem begins on Page 134.

ZIRCALOY-BASE fuel alloys were tested with a large number of variables to ascertain the factors determining the corrosion rate. Turn to Page 137.

CONTENTS

Page

This Month in Corrosion Control 3

More About Conservation of Iron Resources—An Editorial 7

TECHNICAL TOPICS

Page

Case Histories Indicate Tetrafluoroethylene-Lined Pipe Has Lower Installed Cost Than Other High Temperature Piping
By T. R. Thierry 9

Applying Reinforced Plastics in Corrosive Environments of the Process Industry—Design Considerations
By Fred W. Arndt 14

Laboratory Screening Tests of Sprayed Linings for Chemical Process Equipment—Materials Evaluation Program
By R. S. Foster 26

Characteristics, Testing and Some Design Considerations Applicable to Glass Reinforced Plastic Pipe
By R. M. Levy 33

Generic Terms and Manufacturers Listed for 38 More Plastics—Second Table 40

Some Results From High Temperature Testing of Polyester Castings and Laminates
By S. S. Feuer and A. F. Torres 44

RECORD AND REPORT

Page

Lead Cable Submerged in Water Protected by Neoprene Jackets 49
University of Utah Studies Vanadium Extraction From Oil 49
Three NACE Members Give Papers at European Meeting 49
Polyester Resin Plugs Used in Meters. 49
Eighty-Foot Stacks of Polyvinyl Chloride for Corrosive Fumes 49
Thermosetting Epoxy Resin Used for Rapid Pipe Repairs in Field 50
International Congress Names Godard as Officer 50
AIME Book Published 50
New Plants 50
Steering Jets on Rockets Are Coated With Pure Gold 51
Rail Welding System Cuts Time and Labor 40 Percent 51
Arc Temperatures Can Be Adjusted on Plasma Gun 51
International Pipeline Exhibition to Be Held April 19 51
Reinforced Plastic Pipe Used to Handle Corrosive Wastes 52
Book News 52
Plant Inspection Set Up for Oil Field Tubing to Catch Possible Corrosion Failures 54
Chemistry Congress Held 54
Reinforced Polyester Resins Resist Corrosive Fume Attack 56
Papers Given on Corrosion Study Uses of Isotopes 56
High Temperature Meeting 56
Periodicals 56
Ocean Environment Study 56
Thermoelectric Power Used for Heater Fans and Lighted Buoys 58
Vinyl Plastic Sheet Used for Water Reservoir Liner 58
New Products 62
Men in the News 65

Index to Advertisers 6

Advertised in This Issue 6

Corrosion Abstracts 77

NACE NEWS

Page

Plans Being Completed for Buffalo Conference 67
Technical Program to Include Nineteen Symposia, Lectures 67
Ninety Percent of Booth Space Sold for Corrosion Show 67
Photographs of 1961 Buffalo Conference Program Chairmen 68
South Central Region News
Houston Section to Hold Feb. 2-3 Short Course 69
New Orleans Section 69
North Texas Section 69
Sabine-Neches Section 69
Shreveport Section 69
Panhandle Section 69
East Texas Section 69
Rocky Mountain Section 69
Greater Baton Rouge Area Section .. 69
Southeast Region News
Record Attendance at Atlanta Confernece 70
Ohio Valley Section 70
J. Frank Putnam Reads His Own Obituary 70
Ohio State University Short Course Has Registration of 119 71
North Central Region News
Pascoe Given Cook Award at Detroit Section Meeting 71
Twin City Section 71
Detroit Section 71
Canadian Region News
Paper Added to Nov. 14-15 Eastern Division Program 73
Vancouver Section 73
Toronto Section 73
Edmonton Section 73
Montreal Section 73
Appalachian Short Course Committee Chairmen to Meet 73
National and Regional Meetings and Short Courses 73
Northeast Region News
Well-Oriented Program Given at Huntington Conference 74
Trustees Weigh Plans to Build, Improve Region 74
Plans for New York Meeting Are Outlined 74
Uninformed Citizen Is Peril, Speaker Warns 75
Greater Boston Section Mails Program Brochure 76
Baltimore-Washington Section 76
Metropolitan New York Section 76
Kanawha Valley Section 76
Western Region News
Total Attendance of 250 Counted at San Francisco 76
California Short Course Registration Totals 60 76
San Francisco Bay Area Section 76
Portland Section 76
Central Arizona Section 76
Section Calendar 76

DIRECTORIES

Page

NACE Officers, Directors and Staff Members 88
NACE Region and Section Officers ... 142

CONTENTS

TECHNICAL SECTION

Page

Selective Corrosion of Inconel—A Technical Note
By R. Bakish and F. Kern 89

Corrosion Problems in the Use of Dense Salt Solutions As Packer Fluids
By C. M. Hudgins, J. E. Landers and W. D. Greathouse 91
Discussion: Glenn Ray Roberson, Kelly H. Roach, Page 94; Replies by C. M. Hudgins, Page 94

Stress Corrosion Cracking of High Strength Oil Country Tubular Goods
By R. S. Ladley 95
Discussion: R. F. Weeter, John H. Naschke, E. H. Muehlhaase, L. W. Vollmer, Page 98; Reply by R. S. Ladley, Page 98

New Developments in the Mitigation of Corrosion in the Utility Field
By E. H. Thalmann 99

Cracking of Low Carbon Steel by Ferric Chloride Solutions
By Mary Boehm Strauss and M. C. Bloom 109

Stress Corrosion Cracking of Carbon Steels In Concentrated Sodium Nitrate Solutions
By R. L. McGlasson, W. D. Greathouse and C. M. Hudgins 113
Discussion: Parke D. Muir, John H. Naschke, L. W. Vollmer, Charles E. Fox, Page 118; Replies by R. L. McGlasson, Page 118

Practices and Experience With Protective Jackets for Outside Plant Lead and Aluminum Sheathed Cable—A Report Prepared Jointly by NACE Task Group T-4B-5 on Non-Metallic Sheaths and Coatings, and by The AIEE Sheaths and Coverings Subcommittee—Publication 60-14 119

Corrosion of Nuclear Power Plant Tube Materials by Boiler Sludge
By E. Howells, T. A. McNary and D. E. White 127
Discussion: F. W. Fink, Page 132; E. A. Tice, C. L. Fitzgerald Jr., Page 133; Replies by E. Howells, Page 133

High Temperature Furnace Corrosion of Type 309 Alloy Steel
By R. D. Merrick 134

Factors Governing the Corrosion Testing of Zircaloy-Base Fuel Alloys
By S. Kass and R. F. Gessner 137

Focus on Plastics in Process Equipment
Pages 9-48

Copyright 1960 by the National Association of Corrosion Engineers. Reproduction of the contents, either as a whole or in part, is forbidden unless specific permission has been obtained from the Publishers of CORROSION. Articles presented represent the opinions of their authors, and not necessarily those of the Editors of CORROSION, nor the Officers or Members of the National Association of Corrosion Engineers. Manuscripts to be considered for publication should be forwarded, together with illustrations, to the Editor of CORROSION, 1061 M & M Building, Houston 2, Texas.

Corrosion

Published monthly as its official journal, by the National Association of Corrosion Engineers, Inc., at Houston, Texas, U.S.A., as a permanent record of progress in corrosion control.

Vol. 16 November, 1960 No. 11

EDITORIAL STAFF

IVY M. PARKER—Editor

JAMES T. LONGINO
Technical Editor

DALE MILLER
Editorial Assistant

EDITORIAL REVIEW COMMITTEE

FRED M. REINHART, Chairman, National Bureau of Standards, Washington 25, D. C.

Mark F. Adams
A. L. Alexander
Joseph Bigos
W. W. Binger
W. B. Brooks
W. E. Bunting
I. C. Dietze
A. C. Elm
Otto H. Fenner
N. D. Greene
John J. Halbig
B. C. Haworth
T. L. Hoffman
Harry J. Keeling
Frank E. Kulman
Hugh L. Logan
Thomas A. Lowe
D. W. McDowell, Jr.
R. L. McGlasson
Dwight G. Moore
Charles C. Nathan
J. W. Nee
V. B. Pike
A. P. Richards
A. H. Roebuck
J. D. Sudbury
D. H. Thompson
Sidney Tudor
R. M. Wainwright

CORRESPONDENTS

Cecil Phillips, Jr.—Petroleum Refining
K. G. Compton—Telephone, Telegraph and Radio
S. W. Shepard—Non-Metals
Leonard C. Rowe—Transportation Industry
H. E. Stover—Fresh and Salt Water
W. A. Szymanski—Chemical Industry
Gordon B. Smith—Non-Ferrous Metals
Norman D. Groves—Pulp, Paper, Mining and Food
V. M. Kalhauge—Petroleum Production and Pipe Lines
C. P. Larrabee—Ferrous Metals
Herbert W. Dieck—Power
Robert E. Brooks—Light Metals

BUSINESS STAFF

NORMAN E. HAMNER
Managing Editor and Advertising Manager

T. J. HULL
(Executive Secretary NACE) Business Manager

BRAND and BRAND
Western States Advertising Representatives
6314 San Vicente Blvd., Los Angeles 48, Cal.

Address all communications to:
1061 M & M BUILDING
Houston 2, Texas

SUBSCRIPTION RATES (Post Paid)

NON-MEMBERS NACE, CALENDAR YEAR:
U.S. territories & possessions, Canada and Mexico $11
All other addresses $15

SINGLE COPIES, 1958 to Date:
Non-members NACE ..... $ 2
NACE members ..... $ 1

Single copies 1956 to 1958 ..... $ 2

Libraries of educational institutions, and Public Libraries, U.S., Canada and Mexico only calendar year ..... $ 4

LOST OR DAMAGED COPIES: Claims for replacement without cost must be received within 60 days of date of issue.

Foreign remittances should be by international postal or express money order or bank draft negotiable in the U. S. for an equitable amount in U. S. funds. Second-class Postage Paid at Houston, Texas

CORROSION Is Indexed Regularly by Engineering Index and Applied Science and Technology Index.

TECHNICAL REPORTS

on

CORROSION PROBLEMS in the PROCESS INDUSTRIES

TP-5A Materials of Construction for Handling Sulfuric Acid. *Corrosion*, August, 1951, issue. Per Copy $1.50.

T-5A Qualified Approval for D-319 Analysis Austenitic Chromium-Nickel-Molybdenum Stainless Steel. A Report of NACE Technical Unit Committee T-5A On Corrosion in Chemical Processes. Publication 60-10. Per Copy $1.50.

T-5A-3 Corrosion by Acetic Acid—A Report of NACE Task Group T-5A-3 On Corrosion by Acetic Acid. Pub. 57-25. Per Copy $2.50.

T-5A-4 A Bibliography on Corrosion by Chlorine. A Report of Technical Unit Committee T-5A on Corrosion in the Chemical Manufacturing Industry. (Compiled by Task Group T-5A-4 on Chlorine.) Pub. 56-2. Per Copy $2.00.

T-5A-4 Summary of Replies to Questionnaire on Handling of Chlorine Mixtures—A Report of NACE Task Group T-5A-4 on Chlorine. Pub. 59-15. Per Copy $1.50.

T-5A-5 Corrosion by Nitric Acid. A Progress Report by NACE Task Group T-5A-5 on Nitric Acid. Per Copy $1.50.

T-5A-5 Aluminum vs Fuming Nitric Acids. A Report by NACE Task Group T-5A-5 on Corrosion by Nitric Acids. Per Copy $1.50.

T-5A-6 Summary of Replies on Corrosion in HF Alkylation Units—A Report of NACE Task Group T-5A-6 on HF Corrosion. Pub. 59-14. Per Copy $1.50.

T-5B High Temperature Corrosion Data. A Compilation by NACE Technical Unit Committee T-5B on High Temperature Corrosion. Pub. 55-6. Per Copy $1.50.

T-5B-3 The Present Status of the Oil Ash Corrosion Problem. A Progress Report of NACE Task Group T-5B-3 on Oil Ash Corrosion. Pub. 58-11. Per Copy $1.50.

T-5B-3 The Residual Oil Ash Corrosion Problem, by C. J. Slunder and Bibliography for Residual Fuel Oil Ash Corrosion. A Report of NACE Technical Unit Committee T-5B, High Temperature Corrosion, prepared by Task Group T-5B-3 on Oil Ash Corrosion. Publication 60-6. NACE Members $2.00; Non-members $2.50 Per Copy.

T-5C-1 Some Economic Data on Chemical Treatment of Gulf Coast Cooling Waters. A Report of the Recirculating Cooling Water Sub-Committee of NACE Task Group T-5C-1 on Corrosion by Cooling Waters, South Central Region. Per Copy $1.50.

T-5C-1 Water Utilization and Treatment Efficiency of Gulf Coast Cooling Towers—A Report of the Recirculating Cooling Water Work Group of NACE Task Group T-5C-1 on Corrosion by Cooling Water (South Central Region). Pub. 57-20. Per Copy $1.50.

T-5C-1 Evaluation of Laboratory Testing Techniques for Cooling Water Corrosion Inhibitors. A Report of Task Group T-5C-1 on Corrosion by Cooling Waters (South Central Region). Pub. 57-12. Per Copy $1.50.

TP-5C Stress Corrosion Cracking in Alkaline Solutions. Pub. 51-3. Per Copy $2.00.

T-5E Report on Stress-Corrosion Cracking of Austenitic Chromium-Nickel Stainless Steels. Sponsored jointly by ASTM Committee A-10 on Iron-Chromium, Iron-Chromium-Nickel and Related Alloys, and NACE Technical Unit Committee T-5E on Stress-Corrosion Cracking of Austenitic Stainless Steels. ASTM Special Technical Publication No. 264. Members $4.80; Non-members $6 Per Copy.

Remittances must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 65c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

1061 M & M Bldg. Houston 2, Texas

ADVERTISED IN THIS ISSUE

A

ANODES
- Graphite 59
- Magnesium 85
- Special Shapes 17
- Zinc 17

B
- Backfill, coke breeze 75
- Bushings, dielectric 38

C

CATHODIC PROTECTION
- Engineering ...48, 66, 69, 75, 85
- Rectifiers 40, 83, 85

COATINGS
- Application services 22, 23
- Asphalt mastic 60, 61
- Cellulose 23
- Chlorinated polyether....22, 23
- Coal tar 13, 60, 61
- Coal tar-epoxy 60, 61, 81
- Cold set 12
- Epoxy 23, 81
- Galvanized 32
- High Temperature 18, 68
- Industrial 12, 18
- Inorganic zinc 2
- Maintenance 2
- Mastic 13
- Neoprene 35
- Nylon 23
- Pipeline enamels 60, 61
- Plastic 25
- Pipelines 37, 56, 70, 78
- Polyethylene 23, 30
- Synthetic rubber 35
- Vinyl 23
- Zinc filled epoxy..... 58

Concrete, acid proof..... 16

Corrosion surveys 66

G

Galvanized sheets 32

I

INHIBITORS
- Acid Cleaning 62
- Oil well 1, 11
- Oil field 57
- Pickling 62
- Pickling Acid 46, 47
- Refinery 53, 57

INSTRUMENTS
- Corrosion meter 20
- Pipeline detector 65
- Probes 20
- Thin film detector..... 65

Insulation, acid proof.....42, 43

L

LININGS
- Chlorinated polyether 29
- Pipeline, plastic 25
- Polyvinyl chloride 15

N

Nickel tanks 17

P

PIPE
- Asbestos cement 71
- Plastic lined steel..... 41

PIPELINES
- Asbestos felt 51, 81
- Casing seals 81
- Coating services...37, 56, 70, 78
- Glass wrap 81
- Plastic linings 25
- Polyethylene coating 30
- Primers 30
- Rock shield 51, 81
- Tar enamels 60, 61
- Wrapping 55, 56, 70, 78

PLASTICS
- Bisphenol polyester resin.... 39
- Bushings, dielectric 38
- Conduit 32
- Custom molding, laminating 52
- Glass reinforced polyester.. 63
- Pipe linings 25, 41
- Polyester resin equipment... 19
- Process equipment.19, 22, 24, 39
- Reinforced vinyl 63
- Structural panels 52
- Tank linings 15

PROCESS EQUIPMENT
- Ducts, plastic 52
- Gas scrubber 39
- Nickel tanks 17
- Pipe, plastic 52
- Plastic coated 22, 23
- Steel pipe, plastic lined..... 41
- Polyester resin 19
- Scrubbers, plastic 24, 63
- Stainless steel 79
- Tanks 17, 52

Rectifiers 40, 83

S

STEEL
- Stainless 32, 79
- Test specimens 40

Surveys 85

T

TANKS
- Linings 15, 29
- Nickel 17

TAPE
- Polyethylene 8, 72, 73
- Polyethylene pipe joint..... 30
- Polyethylene, pressure sensitive 55

Testing services 66

Test specimens 40

V

Valves, plastic coated..... 22

W

Water Treatment 66

INDEX TO ADVERTISERS

Vol. 16 November, 1960 No. 11

- Amchem Products, Inc.....46, 47
- Amercoat Corporation.....Inside Front Cover
- American Cyanamid Plastics and resins Division..... 19
- Atlas Powder Company..... 39
- Cahill Plastics 52
- Carboline Company 2
- Cathodic Protection Service..... 48
- Chase & Sons, Inc..... 55
- Consolidated Mining and Smelting Company of Canada Limited, The..... 17
- Corrosion Engineering Directory..... 66
- Corrosion Rectifying Company..... 85
- Corrosion Services, Inc..... 69
- Corrosion Test Supplies..... 40
- Crest Intsruments 20
- Developments Unlimited Incorporated Devlimco 62
- Dowell ..... Back Cover
- du Pont, E. I. de Nemours & Co., Inc..... 35
- Duriron Company, The.....Inside Back Cover
- du Verre, Incorporated..... 24
- Eicor, A Division of The Scranton Corporation..... 83
- Electro Rust-Proofing Corporation..... 75
- Garlock Packing Company, The..... 29
- Good-All Electric Manufacturing Co..... 40
- Heil Process Equipment Corporation..... 63
- Hercules Powder Company Cellulose Products Department..... 22
- Hill Hubbell Company..... 56, 70, 78
- Humble Oil & Refining Company..... 53
- International Nickel Company, Inc. Huntington Division 79
- Japanese Commercial Consulting Service.. 68
- Johns-Manville Corporation Industrial Water Pipe..... 71
- Kendall Company, The Polyken Sales Division.....72, 73
- Koppers Company, Inc. Tar Products Division..... 13
- Markal Company 18
- May Products, Inc..... 38
- Minnesota Mining and Manufacturing Company, Electrical Products Div..... 8
- National Association of Corrosion Engineers 6, 71, 87
- National Carbon Company Division of Union Carbide Corporation.. 59
- Perrault Supply Company Div. of Allied Paint Mfg. Co..... 81
- Pittsburgh Chemical Company Protective Coatings Division.....60, 61
- Pittsburgh Corning Corporation.....42, 43
- Polyken Sales Division The Kendall Company.....72, 73
- Polymer Corporation, The Whirlclad Division 23
- Positions Wanted and Available..... 64
- Republic Steel Corporation.....30, 31, 32
- Resistoflex Corporation 41
- Ruberoid Company, The..... 51
- Sauereisen Cements 16
- Sealube Company, The..... 58
- Tinker & Rasor..... 65
- Tretolite Company, Division Petrolite Corporation 1
- Tube-Kote, Inc. 37
- Tubular Lining Corporation..... 25
- U. S. Stoneware Company..... 15
- Universal Oil Products Company..... 57
- Visco Products Co., Inc..... 11
- Wholesale Coke Company..... 75
- Wisconsin Protective Coatings Co..... 12

More About Conservation of Iron Resources

RECOGNITION of the increasing need to conserve the nation's resources of iron is growing. The most recent—and one of the most interesting—commentaries on this need comes from the Institute of Scrap Iron and Steel, Inc. This organization, supported by many of the Nation's dealers in scrap materials, has issued a folder describing some of the advantages to be obtained from using scrap. The following extracts are significant to corrosion engineers.

When iron and steel scrap is used in place of pig iron, it saves both money and resources. When it replaces iron ore and pig iron in furnaces, it reduces melting time, and thus reduces the cost of steel. Because pig iron is made by smelting iron ore, some substantial savings favor the use of scrap because:

1. Ore mined and used in the United States averages about 50 percent iron, so it takes two tons of ore to make one ton of pig iron.

2. About a ton of coke and half a ton of limestone are consumed in making a ton of pig iron. Small amounts of other materials are used, too. To produce a ton of pig iron, between 3½ and 4 tons of exhaustible natural resources are used, not including fuel.

Foreign ores are being imported in increasing volume to make up for the increasing deficiency of high-grade ores produced in the United States. This is a weak leak in the nation's potential in that these supplies may be interrupted in time of war. This means, as it did in the last three wars in which the United States has engaged, that scrap will become a principal source of steel if war comes.

There are three principal kinds of scrap:

1. Obsolescent Scrap—Derived from units which have completed their useful life.

2. Industrial Scrap—Left over when ferrous metal is turned into a useful product.

3. Home Scrap—Residues left from fabrication of plates and shapes at steel mills.

Obsolescence and industrial scrap are collected, processed and sold by scrap dealers. They handle up to 35 million tons a year with a sales volume of $1.5 to $2.5 billions.

While there are no data indicative of what part of this scrap that has accumulated as a result of corrosion damage, it may be assumed that at least some considerable part does. What is more important is that scrap metals exposed to the environment suffer serious depletion from corrosion. The sooner they are processed and recycled, the greater net of useful material is recaptured from the scrap total.

The Institute points out: "The answer to meeting the needs for future requirements is not stockpiling, for scrap will deteriorate. Heavier material takes a long time to oxidize, but over a long period of time a thin steel sheet, like a car fender, will rust away completely. Thus, if scrap is not used, rusting can be an important loss factor."

FREE SAMPLE

NEW ALL-WEATHER "SCOTCHRAP" BRAND PIPE PROTECTION TAPE NO. 40

Now—an all-season tape that handles the toughest jobs. Ideal for field-wrapping under cold weather and other adverse climatic conditions. Provides excellent insulation properties and improved electric strength; resists acids, alkalies, salts, oils, gasoline and naphtha. Try it yourself and see . . . send in the coupon below for your free 9-foot sample roll.

——————SEND IN TODAY——————

3M Co., Dept.EAM-110, 900 Bush Ave., St. Paul 6, Minn.
Send me my free sample roll of your new all-weather "SCOTCHRAP" BRAND Pipe Protection Tape No. 40.

NAME_____

COMPANY_____

ADDRESS_____

CITY_____ STATE_____

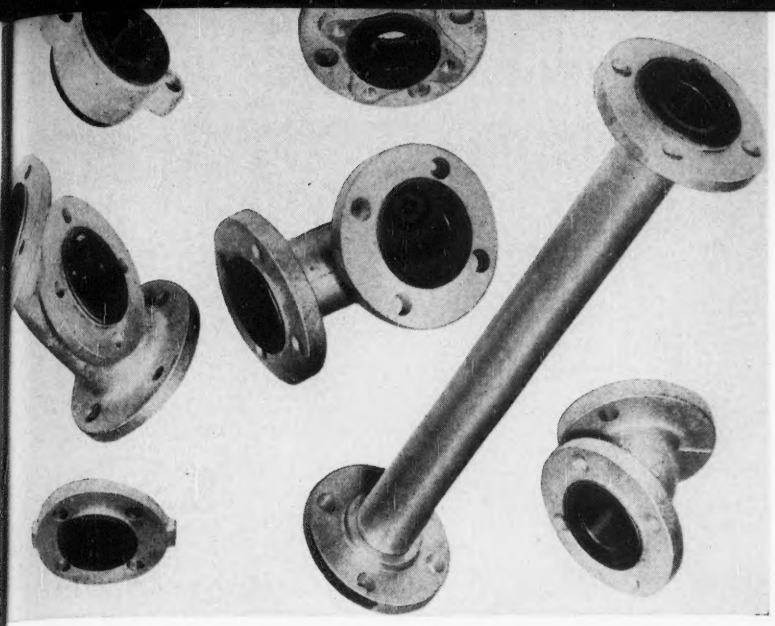
ELECTRICAL PRODUCTS DIVISION

MINNESOTA MINING AND MANUFACTURING COMPANY

3M COMPANY

...WHERE RESEARCH IS THE KEY TO TOMORROW

"SCOTCHRAP" IS A REGISTERED TRADEMARK OF 3M CO., ST. PAUL 6, MINN. EXPORT: 99 PARK AVE., NEW YORK 16, CANADA: LONDON, ONTARIO.



VARIOUS PIPE AND FITTINGS made of tetrafluoroethylene are shown at left. Pipe is Schedule 40 or 80 seamless carbon steel assembled with 150-lb ductile iron or steel flanges. The plastic liner extends over the full gasket face of the flange to separate the housing from contact with corrosive fluids and to eliminate gaskets.

Abstract

Discusses reduced installation costs of tetrafluoroethylene lined steel piping in comparison with glass lined pipe and alloy piping. Describes how this TFE-lined pipe is made and gives recent case histories of installations. 5.4.3

Case Histories Indicate

Tetrafluoroethylene-Lined Pipe Has Lower Installed Cost Than Other High Temperature Piping*

T. R. Thierry

Resistoflex Corporation
Roseland, New Jersey

EXPERIENCE OVER the past three years has shown that tetrafluoroethylene lined piping and fittings (to be called TFE in this article) have a lower installation cost than other piping for high temperature corrosive service.

One company has reported a 30 percent saving in installation cost on $35,000 of TFE pipe and fittings over costs of an equivalent glass lined steel system.

TFE pipe and fittings are not easily damaged in shipping and handling, thus eliminating need for spark testing to detect possible fractures before erection. Flanges do not require inspection with a square during erection to prevent uneven stresses on the faces as bolts are tightened. And, because TFE lining is not rigid, piping does not require rotating along its axis during erection to prevent misalignment. TFE-lined piping requires the same number of hangers required for ordinary steel piping without any need for additional guards, supports or gaskets. Glass-lined pipe may require 50 percent more hangers than ordinary steel piping to reduce sagging which might fracture the rigid glass lining.

TFE lined pipe does not need the expensive annealing and welding required with alloy piping if the welds are to be as corrosion resistant as the pipe.

A detailed study of one installation of 600 feet of 4 and 6-inch TFE pipe showed the TFE-lined piping was erected in less than half the time required for the nickel-copper alloy system being replaced. In this installation TFE piping was used for 80 percent HF and 20 percent water vapor at 230 to 450 F in continuous process. Erection cost was $10,000 in comparison with a $20,000 erection cost for the welded alloy system being replaced.

Another company estimates installation cost for a stainless steel piping system by adding 60 percent to the initial cost of carbon steel piping.[1] This, however, does not include the cost of annealing alloy piping, important when corrosives are being handled.

How TFE-Lined Pipe Is Made

Proper fabrication of polytetrafluoroethylene powder* into reliable corrosion resistant products requires careful controls. Physical characteristics of the final product can vary greatly, depending on molecular weight and particle size of the various powders, production techniques and processing conditions.

Fabrication of polytetrafluoroethylene begins with virgin granular powder which is first compressed into the desired form, followed by baking or sintering cycle at temperatures above its melting point. Particle size and shape of the powder is very important in determining strength and other physical properties of the final product.

Particles in TFE granular powders consist of agglomerated fibers. To obtain the density necessary for optimum physical properties, powder in the preform must be compacted so that these fibrous agglomerates form as tight a matrix as possible. If the die cavity is not uniformly charged or if insufficient pressure is exerted, the matrix will be open, resulting in porosity of the final product. If excessive pressure is applied, a shearing action may occur between charges, resulting in fine cracks or cleavage planes in the final fusion.

Because of the high melt viscosity, extrusion of TFE granular powders generally is accomplished by ram pressure rather than screw pressure. These factors coupled with the high bulk density of the TFE powder generally limits extrusion of tubes in the relatively larger sizes required for lining pipe to heavy wall thicknesses averaging about ¼-inch.

To provide for extruding cross sections below ⅛-inch thickness, and in particular for wire insulation, a very fine tetrafluoroethylene was developed[(1)]

(Continued on Page 10)

★Extracted from a paper titled "Manufacture, Applications and Economics of Teflon-Lined Piping" presented at a meeting of the San Francisco Section, National Association of Corrosion Engineers, April 12, 1960, San Francisco, Cal.

* Teflon, trade mark of E. I. du Pont de Nemours & Co., Inc.

(1) Teflon 6, trade mark of E. I. du Pont de Nemours & Co., Inc.

TECHNICAL TOPICS

FOCUS ON PLASTICS IN PROCESS EQUIPMENT

Pages 9-48

Tetrafluoroethylene –

(Continued From Page 9)

which not only has fine particle size but also extremely fine fibrous texture.

Because these fibers must be oriented, this powder is compounded with lubricants or solvents and processed in a paste or lubricated state. However, because TFE is essentially nonwettable, it packs and lumps when mixed with solvents or lubricants and most other liquids which complicates the problem of trying to get uniform extrusions. Weak spots, flaws and generally inconsistent physical properties may result. Ordinarily, agglomerates of this type can be eliminated by mechanical mixing in a mill, but this mixing tears the fine fibers, resulting in a product with poor physical properties.

A patented process[2] has been designed to make more uniform extrusions by incorporating small amounts of carbon black into the lubricated compound. The carbon black constitutes a small fraction of one percent, often no more than some of the impurities of reactant products in the TFE polymer which is commercial tetrafluoroethylene and not chemically pure in USP sense. This carbon black additive gives TFE linings the characteristic black appearance as seen in the photographs.

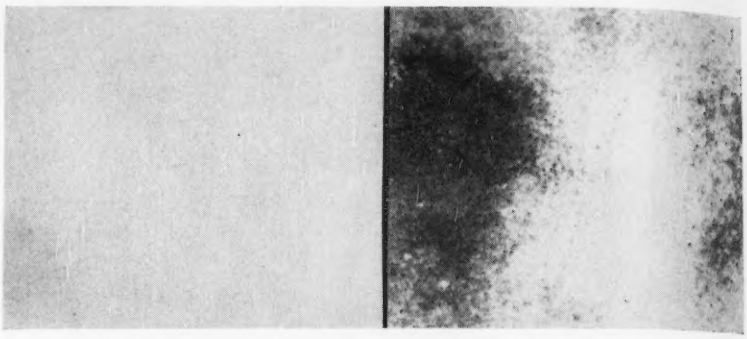
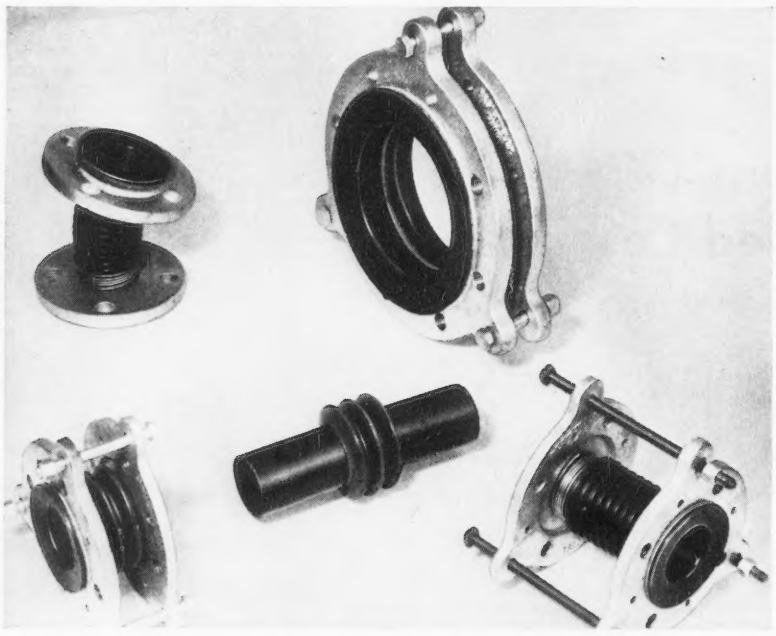


Figure 1—Porosity dye test performed on two 1/16-inch TFE sheets molded by the same process. The only difference between the two was the time and care exercised in distributing and leveling the powder in the preform mold. Improper techniques resulted in the porous sheet on the right which absorbed dye during the 5-minute test. Tensile strength of the porous sheet was half that of the non-porous sheet on left. Porosity also affected elongation, permeability and flex life.



MOLDED BELLOWS made of tetrafluoroethylene are designed to give expansion, flexible and vibration joints tested to withstand 100,000 cycles. They are used in correcting thermal expansion and vibration problems on process equipment such as heat exchangers, condensers, pumps and pipe that are constructed of fragile materials.

Carbon black, a non-polar material, disperses readily when mixed with the fine TFE powder which also is non-polar. Carbon distributes itself rather uniformly in and around the TFE particles and absorbs the lubricants added for extrusion purposes without the necessity of overdiluting the TFE powder. Thus, mixture uniformity is maintained in the prescribed proportions between and around the TFE particles with no need for tearing the delicate fibers by mechanical action.

Because of this additive, the lubricants can orient the fibrous particles during compaction in the extruding or molding process, resulting in more uniform products of consistent density with high strength, ductility and flex life.

[2] Fluoroflex-T, trade mark of Resistoflex Corporation.

(Continued on Page 12)

TABLE 1—Typical Installations of TFE Pipe and Fittings

Case History	Quantity of Pipe, ft.	Number of Fittings	Corrodent	Temp., F	psi	Installation Date	Remarks
1.....	3000	800	20% hydrochloric acid mixture of strong organic solvents	275—300	80—130	December, 1956	Replaced high nickel alloy and glass lined piping.
2.....	75	15	50% boiling nitric acid	355	50	May, 1958	Replaced tantalum lined 304 stainless.
3.....	510	290	Dilute hydrochloric acid and bisphenol	100—400	.....	February, 1959	Replaced, glass lined steel and high nickel alloy based on trial pieces installed 1957-59.
4.....	600	60	80% HF acid and 20% water vapor	230—450	.....	April, 1959	Replaced Monel system based on trial spool installed July, 1958.
5.....	130	23	Sludge build-up in system for continous bonderizing of wire	.....	.....	March, 1959	Replaced carbon steel and epoxy pipe based on 3 months trial with no build-up.
6.....	280	75	Dehydrochlorination from hydrocarbon mixture	250	.....	May, 1959	Replaced glass and 316 stainless based on trial spool installed September, 1958.
7.....	1100	280	Dilute hydrochloric acid and copper chloride	150	.....	May, 1959	Replaced glass lined steel based on success of previous application.
8.....	200	28	Hypochlorite sweetening process	.....	.....	June, 1959	Trial piece installed March, 1958.

PROOF OF CORROSION CONTROL

with Visco® ANTI-CORROSION TREATMENT

IT took only 30 days for the two steel coupons shown at right above to corrode almost away in the stream of a secondary-recovery well in Kansas. Both coupons, where not corroded through, are wafer thin. An anti-corrosion chemical was being fed at the rate of one pint per day, yet the average corrosion rate on the coupons was 216 mils* per year.

In the same well, Visco-treated with the same amount of chemical per day, the coupons at left above showed a corrosion rate of only 8.1 mils per year after 29 days' exposure.

Visco Chemicals cut the corrosion rate over 96%!

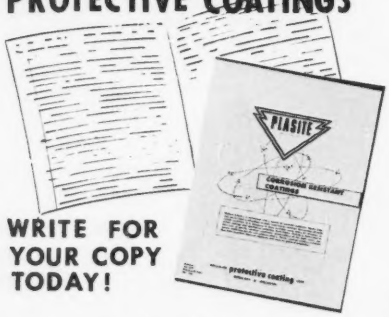
For corrosion control *results* and treating *economy,* call your Visco Representative, *now.*

*1 mil=.001 inch. A corrosion rate of 216 mils per year means that the corrosive attack, if uniform, would have corroded away the entire surface of the metal to a depth of .216 inches in a year. However, the real danger of high corrosion rates, as the coupon shows, is the much deeper and faster penetration occurring at localized areas.

VISCO PRODUCTS COMPANY
INCORPORATED
1020 Holcombe Blvd., Houston 25, Texas
JAckson 8-2495

Visco . . . CONSISTENTLY EFFICIENT OIL INDUSTRY CHEMICALS

Simplify
YOUR SELECTION OF PROTECTIVE COATINGS



WRITE FOR YOUR COPY TODAY!

PROVEN IN THE PROCESS INDUSTRIES
- STEEL TANK LINING
- CONCRETE TANK LINING
- PROTECTION OF STRUCTURAL STEEL, FUME DUCTS AND EQUIPMENT
- CONCRETE FLOORS
- TANK CARS

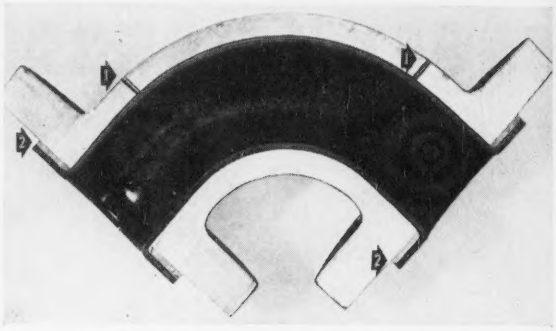
FOR IMMERSION SERVICE
FOR HEAVY DUTY MAINTENANCE SERVICE

COLD SET COATINGS
HEAVY BUILD using standard spray or brush methods.
WIDE CHEMICAL RESISTANCE to acids, caustic solvents, salts, de-ionized water, and aqueous solutions.
HIGH TEMPERATURE RESISTANCE not affected by thermal shock.
AIR DRY field applications.
EXCELLENT BOND — No Primers on white metal blasted surface.

OTHER PLASITE PRODUCTS INCLUDE: CAULKING COMPOUNDS
PRIMERS
BAKING COATINGS

wisconsin protective coating corp GREEN BAY, WIS.
REPRESENTED IN PRINCIPAL INDUSTRIAL AREAS

PLASITE



CROSS SECTION OF ELL shows vent holes (Number one arrows) designed as a simple safety bleed device. Vent holes also warn of any accidental damage to the liner or gasket faces before serious damage occurs to the housing. Number two arrows indicate asbestos backings behind the gasket faces. If organic film or moisture is trapped inside the housing, the holes also permit vapors to escape so that the lining will not collapse when the pipe is subjected to high temperatures with the vapors inside the housing.

Tetrafluoroethylene—

(Contined From Page 10)

Importance of Proper Fabrication

Improper fabrication techniques such as improper charging of the die cavity or insufficient pressure exerted during molding can result in products with porous characteristics illustrated in Figure 1. The two 1/16-inch thick sheets of granular TFE were molded by the same conventional process. The only difference was the amount of time and care exercised in distributing and leveling the powder in the preform mold. A commercial penetrant dye was applied to both finished sheets after they were sintered. After about five minutes, their surfaces were wiped clean. The dye that remained in the sheet on the right indicates the porous areas of varying density.

A government test similar to this dye test has shown that porous TFE sheets may increase 25 percent in weight after immersion in nitric acid and other materials.

Tensile strength of the non-porous sheet on the left was 3,000 psi; that of the porous sheet on the right was only 1,500 psi. Elongation on the left sheet was 200 percent; only 80 percent for the porous sheet on the right. Flex life and permiability between the two sheets varied as much as 1,000 times.

Recent Case Histories Cited

Eight case histories of installation of TFE pipe and fittings are summarized in Table 1, giving the approximate quantity of material, corrosive conditions and date installed.

As with other corrosion resistant materials, consistent performance of TFE products cannot be guaranteed unless proper engineering specifications are given when process equipment is being fabricated. For example, if a low carbon grade of 18-8 stainless steel is required to do a specific job, the specification does not specify mere "stainless steel."

When TFE products are to be used, the specifications should state requirements for special products in terms of freedom from porosity by a dye, electrostatic or other suitable test and flex life requirements by defining the number of cycles required.

Reference

1. Plastic Pipe. *Chemical Engineering*, March 23, 1959

Technical Topics Included in Index

Technical Topics will be included in CORROSION's annual index published in the December issue. The Topics will be cross-referenced in the alphabetical subject and author index.

Persons who customarily extract Technical Section pages from each issue for binding are reminded that the Technical Topics pages should be extracted also for a more complete reference to technical information published in CORROSION.

how CORROSION is indexed

- By Volumes Annually in December Issue
- In NACE Bibliographic Surveys of Corrosion
- In NACE Abstract Punch Card Service
- In 10-Year Index to CORROSION
- In Engineering Index
- In Applied Science and Technology Index

According to Mr. David Greene, of A & G Welding:

"Bitumastic solved our coating problem without delaying our production"

"Part of the reason for the excellent reputation of our swimming pool filters is their long service life," says Mr. Greene, president of A & G Welding and Boiler Co. in South Kearny, N.J. "And protection of the steel interior of these filter tanks against corrosion is an important factor in obtaining this long life," he continues.

A & G tried numerous coatings before selecting Bitumastic® Tank Solution for the job. Some coatings—even more expensive materials—failed due to undercutting; others just took too long to apply and dry, a drawback from the standpoint of maintaining efficient production. Now, tank heads are hand-brushed and the finished, fabricated tank is coated through a port with a specially designed spray gun. The tight, uniform coating film formed by Bitumastic Tank Solution gives long-lasting protection. And, since this coating was specially formulated for potable water applications, it imparts no taste or odor to the pool water processed by the filter.

Just as this Bitumastic coating solved one manufacturer's problem, you will likely find the answer to most corrosion-preventive requirements in one of the ten Bitumastic products. Whether you're coating your plant or your product, Bitumastic coal-tar based protective coatings can help you do it quickly—and less often. Use the coupon for full details. Koppers Company, Inc., Tar Products Division, Pittsburgh 19, Pa. District Offices: Boston, Chicago, Los Angeles, New York, Pittsburgh and Woodward, Ala. In Canada: Koppers Products, Ltd., Toronto.

SEE OUR CATALOG IN SWEET'S
OR WRITE FOR COPY

KOPPERS
BITUMASTIC
COATINGS AND ENAMELS
another fine product of COAL TAR

KOPPERS COMPANY, INC.
Tar Products Division
Dept. 100-L
Pittsburgh 19, Pa.

Gentlemen:
Please send me more information on the Bitumastic family of protective coatings.

Name_____

Firm_____ Title_____

Address_____

City_____ Zone____ State_____

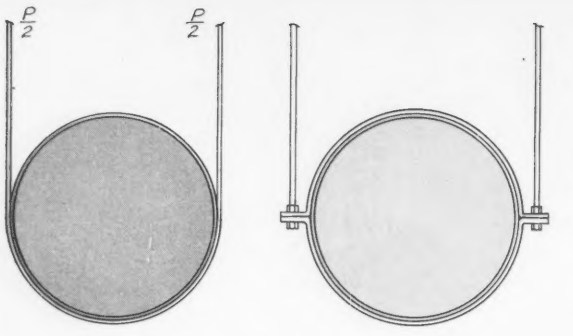


Figure 1—Band-type duct hanger.

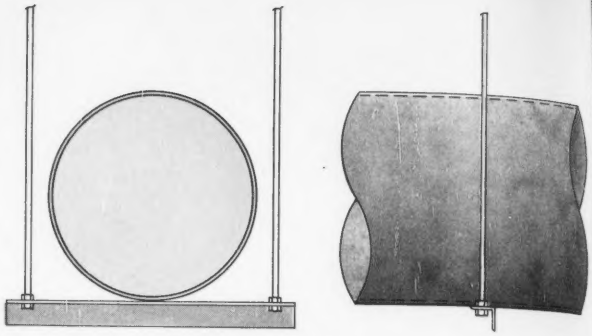


Figure 2—Trapeze-type duct hanger.

Design Considerations

Applying Reinforced Plastics in Corrosive Environments of the Process Industry*

Fred W. Arndt

Heil Process Equipment Corporation
Cleveland, Ohio

Abstract

Design considerations for applying reinforced plastic materials of construction to corrosive service in the process industries are reviewed from an over-all standpoint. Considerations affecting the basic design, such as material selection and fabrication techniques, are related to mechanical or structural characteristics. Factors concerning the application, such as strength required for normal service, mechanical abuse, thermal conditions and chemical attack are discussed. Design must also include considerations for installation, anticipated service life and variations in values caused by random production influences. Each of these items are related to case histories, and examples for employing these values to conventional design techniques are presented. 5.11

Introduction

THE SUCCESS or failure of many installations of plastic process equipment is frequently a matter of mechanical design rather than corrosion resistance. For this reason a sound application requires that consideration be given to the physical properties of the plastic materials of construction in, as nearly as possible, the anticipated operating environment. Exact data for the various physical properties of reinforced plastics frequently cannot be found for specific operating environments. In these cases approximations are necessary and generally are made conservatively. In the following sections an attempt is made to illustrate one such approach to successful design of reinforced plastic structures.

Discussion

In the application of reinforced plastics in the process industries, design considerations must be related to the mechanical and chemical properties of the available materials. First, of course, the resin and reinforcing fiber are selected to be satisfactory from a corrosion standpoint. This selection embraces much study and often, for special cases, involves compromises.

Material selection generally is based on the service involved from a corrosion standpoint. Both reinforcement and bonding resins must be considered. Most frequently glass fiber is employed. Exceptions may be made when reagents attack glass, as does hydrofluoric acid, for example. In such cases other plastic reinforcing materials or fibers are selected.

Resins can be one of many basic types or of special modifications within a type. Phenolics, polyesters, furanes and epoxies are commonly employed. Specific corrosion resistance data concerning the particular resin formulation can be obtained from the resin manufacturer's literature and from testing programs which have been conducted by fabricators, government agencies, universities and other sources reported in the literature. Above all, actual case histories of field applications should be called on as a guide to selection.

Once the resin-fiber combination has been selected, the method of manufacture of the specific item of equipment must be considered. Generally, industrial equipment does not require a large number of identical pieces (as in the consumer market) but rather single, individual items or items in small numbers with limited repetition.

Typical process industries equipment made of plastic are tanks, tank covers, fume exhaust hoods, ducts, exhaust stacks, fans, fume scrubbers, piping, mixers, chutes, launderers, hoppers and various other shapes and containers. Low-volume, specialized items like these do not lend themselves to "mass production" techniques. Rather, hand lay-up, machine-assisted contact pressure molding methods appear to be economical when comparatively low cost tooling and molding is indicated. The higher strength materials produced by pressure molding require expensive molds and related equipment. Unless quantity production or extreme performance is required (such as in military or aircraft applications), price considerations do not favor the higher strength laminates. So, the lower strength laminates of the contact pressure methods are of principal interest. Although not conclusively proved, there is some evidence that such laminates, because of their higher resin content, may have better corrosion resistance. Also contact pressure methods favor resin-reinforced sequences arranged for optimum chemical resistance.

Mechanical Requirements

After a satisfactory material of construction has been selected from a chemical standpoint, and the most economical method of manufacture resolved, it then becomes necessary to establish as clearly as possible the mechanical requirements. It is at this point that perhaps the greatest hazard of mis-application exists.

Data reported in the literature frequently are for pressure molded samples of high glass (or reinforcing fiber) content. These data may tend to mislead those who would, on this evidence, have the tendency to think in terms of very high strengths, or, in other cases, high temperature resistances. Unless the item in mind can be manufactured economically by methods similar to those by which such high strength samples were manufactured, the result is apt to be disappointing. If contact pressure methods are most economical for the specialized and low repetitive volume type of production typical of the process industries, then the values typical for equipment fabricated by this method must be used in analysis.

Actual Environment Is Factor

Many tables are published of the physical properties of reinforced plastics. Their indiscriminate use will almost certainly lead to failures because of inadequate mechanical strength of the fabricated item if it is required to withstand critical loadings. It seems almost an over-simplification to say that the mechanical properties of the reinforced plastics should be evaluated for the actual environment in which the product is to be employed. This, however, frequently is impractical, so conservative approximations often are necessary. There are at least five broad areas which should be investigated. (In specific cases

(Continued on Page 16)

★ A paper presented at the North Central Region, Conference, National Association of Corrosion Engineers, Cleveland, Ohio, October 20-22, 1959.

How can you be SURE that your Tank Linings are MATCHED TO YOUR NEEDS?

Tank lining failures can be mighty expensive in terms of ruined tanks and disrupted production schedules. That's why low cost linings sometimes prove to be the most expensive in the long run.

On the other hand, the extra money spent for protection that's not needed would be better invested elsewhere in the plant.

Selection of the proper tank lining material is frequently a confusing job for the man who's not an expert. The best course is to follow two simple, logical rules:

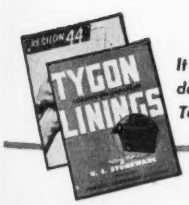
1. *Draw on the experience of a tank lining specialist.* One of The U. S. Stoneware Company's fully experienced tank lining engineers . . . who works day-in and day-out with tank lining problems of all types . . . will be pleased to analyze your application; weigh such variables as operating temperatures, corrosive conditions, abrasion resistance requirements, tank construction, and the like; and recommend the one tank lining material that will be best for your job — all without cost or obligation.

2. *Work out your needs with a firm offering a full line of tank lining materials.* Whatever your tank lining problem, The U. S. Stoneware Company produces a material that *exactly* fits your needs: TYGON® modified polyvinyl chloride extruded sheet lining, providing outstanding chemical resistance at temperatures up to 165° F.; KEL-F* trifluorochlorethylene plastic, completely inert to corrosives of all types up to 350° F. (and higher with acid brick oversheathing); PENTON** chlorinated polyether extruded lining, resistant to all alkalies and acids except fuming nitric and fuming sulfuric, at elevated operating temperatures in the range between polyvinyl chloride and the fluorocarbons; RESILON depolymerized rubber-and-resin-based thermoplastic, available either plain or fiberglass-reinforced; ACIKOTE synthetic resin baked-on coating; and others with more specialized applications.

257-G

If you'd like help on a lining problem, simply outline your operation in a letter to The U. S. Stoneware Company. A "U. S." Tank Lining Specialist will be glad to make suggestions and recommendations without cost or obligation.

*Registered Trade Mark, 3M Co.
**Registered Trade Mark, Hercules Powder Co.



It will pay you to investigate! Write today for complete information on "U. S." Tank Linings!

PROCESS EQUIPMENT DIVISION

U. S. STONEWARE
AKRON 9, OHIO

Reinforced Plastics –

(Continued From Page 14)

more factors frequently influence the evaluation.)

1. Physical properties of the reinforced plastic under normal conditions. (Usual values are reported at room temperature for dry specimens tested in air.)
2. Effects of the service temperatures, if other than room temperature.
3. Effects of the service chemicals or moisture.
4. Mechanical factors, such as abuse, vibrations, etc.
5. Production variations which lead to the possibility that products having random values lower than the average reported may be produced.

Table 1 presents a series of approximations for evaluating reductions in the basic strengths of a reinforced plastic to account for anticipated service conditions. The table, which shows values for one corrosive medium, was prepared only to illustrate a method for estimating values which can be applied to conventional design techniques. Obviously the values for the effects of other corrosives and for other conditions have to be determined for each application.

TABLE 1—Approximations for Evaluating Reductions in Basic Strengths of Reinforced Plastics

Useful Proportion of Original Value of Strength [1]	Reference	Comments
(1) Dry Air-Temp. Effect		
75% at 160 F	3	Approx. Range 64 to 86%
92% at 160 F	1	TAC (triallyl cyanurate) modified polyesters. For extreme high temp. performance. Not of general application.
83% at 200 F	1	
(2) Misc. Exposure, Weather, Etc.		
80%	4	
(3) Wet Exposure (Water) Immersed		
212 F—1 week 45%	3	
212 F—6 months 33%	3	
160 F—100 days 42%	7	E [2] dropped from 1.13 to 0.72 x 10^6 psi.
77 F—390 days 66%	7	E dropped from 1.0 to 0.93 x 10^6 psi.
(4) HCl Exposure—Immersed		
Concentrated 212 F 1 wk. 65%	3	
Concentrated 212 F 6 mos. 35%	3	
5% Soln 100 F 100 days 35%	7	E dropped from 1.13 to .68 x 10^6 psi.
5% Soln 77 F 390 days 46%	7	E dropped from 1.0 to 0.52 x 10^6 psi.
(5) Long Term Mech. Use, Vibration, Etc.		
50%	5	
(6) Production Deficiencies		
70 to 90%	1	
96%	2	

[1] Most approximations were based on comparison of flexural strengths.
[2] E above refers to modulus of elasticity in flexure.

Example 1—Fume Duct for Severe Service

As an example of a method for applying the available values to conventional stress analysis formulas for design of process equipment, examine a typical industrial case. A duct system for a large chemical plant in the Eastern U. S. was specified by their engineering company to be manufactured to withstand a 25 psig internal test pressure. The duct was in two sizes, 16-inch and 20-inch diameter. Construction was specified to be glass-reinforced polyester and further specifications were included as to the manufacturer of the polyester resin to be used. Fumes to be handled were from a closed exhaust system involving HCl vapors emitted from a boiling solution.

A. *Wall Thickness*

First, to establish the wall thickness of the duct, it was assumed that the duct system would be adequately supported at the installation; then the American Society of Mechanical Engineers' code formula may be applied as below for the 20-inch diameter duct:

$$t = \frac{pR}{se - 0.6p} \qquad (1)\ \text{Ref. 8}$$

Where:

- t = duct wall thickness (in.)
- p = design pressure (psig). Normally test pressure is 1½ times design pressure, however, to be conservative the 25 psig test pressure is used for design below.
- R = inside radius of duct (in.)
- e = joint efficiency (assume 80%). For straight sections of duct there are no longitudinal joints (e = 100%), however, for this duct system there are longitudinal joints in the two-piece molded sweep elbows.
- s = allowable stress (psi). See Table 1.

The value which requires investigation is s. Since manufacture of this duct work will be by the hand lay-up or contact pressure method, the values for fabrications produced by this method must be reviewed.

(From Table 1)	Tensile Strength, psi
(a) Basic strength of material at room temperature in air. (Typical Value Reported by Manufacturers)	9000
(b) HCl exposure at 212° reduced to 35% of basic value	3150
(c) Reduce to 50% of (b) above for mechanical factor	1570
(d) Reduce to 90% of (c) above for production variations	1415

Substituting in equation (1):

$$t = \frac{25\ (10)}{1415\ (.80) - 0.6(25)} = 0.224\ \text{in.}$$

or a ¼ inch thick wall is indicated for the normal runs of duct and fittings which may have factory-made, welded (or cemented) longitudinal joints. Next, the method of support of the duct must be investigated to determine what effect the stresses introduced at the duct hangers may have upon wall thickness.

For those sections supported with bands, so that an arc of contact of approximately 180 degrees or more (see Figure 1) exists, the wall stresses produced are low and generally can be neglected. The local stresses in the wall are independent of the width of the band. In this case:

$$s_{max} = \frac{kP}{t^2} \log_e \left[\frac{R}{t}\right] \qquad (2)\ \text{Ref. 6}$$

Where

- s_{max} = Maximum value of localized stresses in wall (psi)
- P = Total band support or reaction (lbs.) For hangers at 10 ft. intervals, and 20 in. diameter duct at 15.8 lbs/ft., P = 158 lbs.
- t = Wall thickness (in.) = .25 in.
- R = Duct radius (in). = 10 in.
- $k = 0.02 - 0.0012\ (\beta - 90)$
  - β = arc of contact in degrees, taken as 180°
  - $k = 0.02 - 0.0012\ (\beta - 90)$
  - $= 0.01$

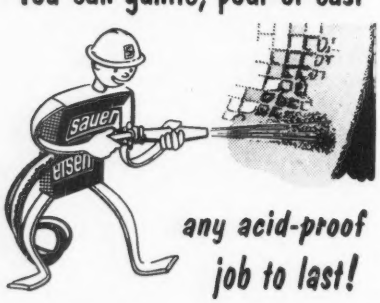
$$s_{max} = 0.01 \frac{158}{.0625} \log_e \left[\frac{10}{.25}\right] = 93\ \text{psi}$$

However, the trapeze type of hanger is frequently employed. (See Figure 2). This produces a point loading which is much more severe than the band or saddle type hanger and should be checked for possible influence on wall thickness selection. Thus, to determine the maximum wall stress caused by this type of hanger, proceed as follows:

$$\text{Max } s'_2 = -\frac{P}{t^2}\left[0.42 \log \frac{0.215R}{b} + \frac{6}{4\pi}\right] \qquad (3)\ \text{Ref. 6}$$

(Continued on Page 18)

You can gunite, pour or cast



any acid-proof job to last!

Yes, Sauereisen Pour-Lay Cement No. 54, the **Acid-Proof Concrete,** is ready to go to work for you, too . . . for floors, tanks, chimneys. Provides resistance to all corrosive acids (except hydrofluoric) and temperatures as high as 2000°F. Can be gunited, poured, cast in forms or applied as a topping over concrete, brick or tile.

Ask for Data Sheets.

Sauereisen Cements Co.
Pittsburgh 15, Pa.

SAUEREISEN
POUR-LAY CEMENT **No. 54**
PAT. APPLIED FOR

For Safe, Cathodic Protection

Specify COMINCO BRAND ZINC ANODES

MADE IN CANADA
COMINCO
TYPE P-432
Type P. For ship hulls, ballast tanks, etc.
MADE IN CANADA
COMINCO
TYPE Z1
Type Z.1
For bolting to ship hulls, piers or docks.
TYPE H.
COMINCO
TYPE-H1BG
For use where space is limiting factor — heat exchangers, condensers, etc.
Type B. For bolting or welding to stationary steel structures.
Type A. A general use anode.
COMINCO
COMINCO
Type R. For use on ballast tanks and other bare steel structures.

AVAILABLE IN A WIDE RANGE OF SHAPES AND SIZES TO PREVENT CORROSION OF STEEL WITH MAXIMUM ECONOMY.

● COMINCO BRAND ZINC ANODES do not require complex installation and will not overprotect, thus giving **maximum anode life.**

● They are **self-regulating,** automatically increasing or decreasing current supply as changing conditions may require.

● COMINCO BRAND ZINC ANODES are made from electrolytically refined Special High Grade Zinc to which carefully controlled additions have been made.

● They are **especially designed** for different services such as **ship hulls, ballast tanks, piers and docks, heat exchangers and pipe lines.** The requirements of these services indicate specific design is necessary to give maximum economy and effectiveness.

● Many new anode designs have been developed by Cominco as a result of recent research. Of particular importance is the range of **new, long thin shapes** which tests have shown combine the advantages of **high current output per pound, improved self-regulating properties, less weight and lower capital cost.**

● COMINCO BRAND ZINC ANODES are designed for **easy installation** either by bolting or welding to the structure to be protected. All anodes have a **specially-designed insert** bonded to the anode metal, giving a permanent positive electrical connection for the full life of the anode.

To help you achieve effective cathodic protection — our Technical Service will be glad to be of assistance.
Write for our descriptive brochure on COMINCO BRAND ZINC ANODES.

COMINCO

THE CONSOLIDATED MINING AND SMELTING COMPANY OF CANADA LIMITED
Phone AVenue 8-3103 • 215 St. James Street, W., Montreal 1, Quebec. • Cable Cominco

CATHODIC PROTECTION WITH ZINC IS COMPLETE PROTECTION

017

Reinforced Plastics –

(Continued From Page 16)

Where: P, t, and A are as above
b = equivalent radius of area of contact.
Approximate b = 0.25 in.

$$\text{Max } s'_2 = -\frac{158}{.0625}\left[0.42 \log \frac{(0.215)\ (10)}{0.25} + \frac{6}{4\pi}\right] = 2200 \text{ psi.}$$

This wall stress exceeds the value of 1415 psi selected previously as the maximum allowable stress for this case. Thus a heavier wall is indicated (assuming the same 10-foot hanger spacing and the use of trapeze type of hanger).

By employing a ⅜ inch thick wall and substituting for this thickness in Equation (3) above find:

$$\text{Max } s'_2 = 975 \text{ psi.}$$

Thus a ⅜ in. thick wall is satisfactory.

B. *Flange Thickness*

Analysis of the flanges is not particularly simple. An American Standards Association 150 lb. standard flange for 20-inch OD pipe is 1 11/16 inch thick. Obviously flanges employing this much material would be expensive. Because the plastic materials are costly (compared to steel), it becomes worthwhile to depart from ASA standards and design for the conditions at hand.

In order to arrive at a preliminary determination of thickness for the flanges, the following brief check is made for an assumed thickness of ¾ inch and for the dimensions shown in Figure 3.

When using more conservative values for maximum allowable stress, this, at first examination, would appear to indicate that the ¾ inch thick flange would be too light. However, the method used for attaching the glass fiber reinforced polyester flange results in a stiffer shape than the flatplate case covered above. This would lead one to suspect that the preliminary stress figure reached may be reduced sufficiently to be acceptable, by accounting for the true shape of the flange-to-duct wall joint as shown in Figure 4. Furthermore, the flange is not exposed to exactly the same service environment as the wall of the duct. Thus, the strength of the materials for the points of highest stress concentrations which are not exposed to the hot corrosive may be estimated.

(Continued on Page 20)

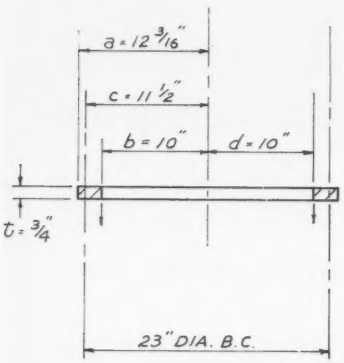


Figure 3—Unattached flat plate flange.

$$\text{Max. } S = -\frac{3W}{2\pi m t^2}\left[\frac{2a^2(m+1)}{a^2-b^2}\log\frac{c}{d} + (m-1)\frac{c^2-d^2}{a^2-b^2}\right] \quad (4) \text{ Ref. 6}$$

Where:

W = 10,000 lbs. (25 psig × area 20" duct and allowances for weight of duct, etc.)
m = Reciprocal of Poisson's ratio = 3.3
t = .75 in.

$$\text{Max. } S = -\frac{30{,}000}{2\pi(3.3)\ (.75)^2}\left[\frac{2(12.1875)^2\ (4.3)}{(12.1875)^2-100}\log\frac{11.5}{10} + (2.3)\ \frac{11.5^2-100}{12.1875^2-100}\right]$$

$$\text{Max. } S = -\frac{3\times 10^4}{10.7}\left[2.65 \log 1.15 + 1.53\right]$$

Max S = —5300 psi

Protect Metals Against Highly Corrosive Conditions...

IN ANY CLIMATE

MARKAL "D-A" COATINGS afford a lasting protection to metals from the ravages of weather and chemical corrosion, salt spray, sulfur fumes, hot acids . . . at temperatures up to 600° F. Also protects against galvanic corrosion between dissimilar metals. Easy to apply with brush or spray. Ideal for inside or outside use.

COMPLETE LINE OF MARKAL COATINGS for all kinds of extreme industrial applications . . . widely used, economical, thoroughly proved in service, dependable. Write on your letterhead for complete literature, indicate the nature of your requirements.

Markal COMPANY

3051 West Carroll Avenue • Chicago 12, Illinois

CYANAMID

CORROSIONEERING WITH LAMINAC®
POLYESTER RESINS

AFTER YEARS OF CONSTANT ATTACK BY BRINE

This Lixator, an automatic brine-making machine manufactured by du Verre, Inc., Arcade, New York, for the International Salt Company, is constructed of glass-reinforced Laminac polyester resin. It has been on the job for many years—added proof of how Cyanamid's polyester resins solve industry's toughest corrosion problems.

Where other materials fall victim to the constant corrosive attack of saturated salt solution, reinforced Laminac polyester resins come through unharmed. The Lixator shows absolutely no corrosion inside or out. It requires no maintenance. And because it is free of corrosion, contaminant-free brine of high purity can easily be produced.

Find out how reinforced Laminac can solve **your** corrosion problems. For details or technical assistance, get in touch with any Cyanamid office listed below.

AMERICAN CYANAMID COMPANY CYANAMID PLASTICS AND RESINS DIVISION

WALLINGFORD, CONNECTICUT. *OFFICES IN:* BOSTON • CHARLOTTE • CHICAGO • CINCINNATI • CLEVELAND • DALLAS • DETROIT • LOS ANGELES. MINNEAPOLIS • NEW YORK • OAKLAND • PHILADELPHIA • ST. LOUIS • SEATTLE • *IN CANADA:* CYANAMID OF CANADA LIMITED, MONTREAL • TORONTO

Crest INSTRUMENTS

CORROSOMETER®

THE STANDARD FOR CORROSION MEASUREMENT

MODEL CK-2

Licensed under patents of Pure Oil Co. and Standard Oil Co. (Ind.)

A valuable new tool created to meet the demanding requirements of the most advanced techniques used today to control corrosion. The CK-2* is a compact instrument ideally suited for either laboratory or on-the-job operation. It is rugged, easily portable and simple to operate.

*CORRO-DEX USERS... write for details how YOU can get a CK-2.

CORROSOMETER PROBES

A complete line of corrosometer probes for both Laboratory and Industrial use are readily available. All models fit the CK-2. Specification sheets sent on request.

Write today for complete descriptive literature about the CK-2.

Crest INSTRUMENTS

11808 S. Bloomfield, Santa Fe Springs, Calif.

Reinforced Plastics –

(Continued From Page 18)

(From Table 1)	Tensile Strength, psi
(a) Basic strength of material at room temperature in air (as before)	9000
(b) Temperature of flange approximately 160° F outside dry. Reduce to 75%	6750
(c) Miscellaneous outside exposure, weather, etc., Reduce to 80% of (b) above	5400
(d) Mechanical factors 50% of (c)	2700
(e) Production variations 90% of (d) allowable	2430

$$V_o = \frac{\left(\frac{f^2 - h^2 T_1}{2t}\right)(t + 0.2325\, f\, T_1)\, p - 2\, T_2\, (h + 0.5377\, f)\, P}{1.86\, ft + T_1\left[h^2\left(2 + 0.116\frac{f}{t}T_1\right) + 1.6103\, fh + 0.866\, f^2\right]} \quad (5)\ [\text{Ref. 6, 9}]$$

Where:

$$f = \sqrt{at} = \sqrt{(20)\ (.375)} = 3.87$$

$$T_1 = \frac{t^3(3a^2 + 5d^2)}{h^3(d^2 - a^2)}$$

$$= \frac{.42(3 \times 400 + 5 \times 593)}{.42(593 - 400)}$$

$$= 21.5$$

$$T_2 = \frac{3.58\, t^3}{h^3(d^2 - a^2)}\left[\frac{d^2}{3}\log_e\frac{b}{a} + 0.1\,(b^2 - a^2)\right]$$

$$= \frac{3.58\ (.42)}{81}\left[\frac{593}{3}\log_e 1.15 + 0.1(530 - 400)\right]$$

$$= .73$$

Substituting in Equation (5)

$$V_o = \frac{\left(15 - \frac{.42}{1.5} \cdot 21.5\right)\left(.75 + .2325 \cdot 3.87 \cdot 21.5\right)25 - 2(.73)\ (.75 + .5377 \cdot 3.87)10^4}{1.86(3.87)\ .75 + 21.5\left[.561\left(2 + .116 \cdot \frac{3.87}{.75} \cdot 21.5 + 1.61 \cdot 3.87(.75) + .866(15)\right]\right.}$$

$$V_o = -63.5$$

$$M_o = \frac{(h^2\, T_1 + 1.86\, ft)\, V_o + h\, T_2\, P - 0.5\, tp\left(f^2 - \frac{h^2}{2t}T_1\right)}{1.5\, T_1\, h - 3.464\, t} \quad (6)$$

$M_o = 190$ in-lb per in.

Longitudinal bending stress in cylinder at junction with flange.

$$S'_1 = \frac{6\, M_o}{t^2}$$

Where: $M_o = 190$, $t = .75$

$$S'_1 = 2015 \text{ psi} \quad (7)$$

Longitudinal direct stress in cylinder far from flange.

$$S_1 = \frac{P}{\pi\, at} = \frac{10{,}000}{\pi(20).375} = 424 \text{ psi} \quad (8)$$

The same stress transmitted to area at flange = 212 psi.

Maximum longitudinal stress in duct (tension at outer surface at junction with flange).

$$S'_1 + S_1 = 2015 + 212 = 2227 \text{ psi.}$$

Radial direct stress in flange.

$$S_1 = \frac{V_o}{h} + P = \frac{-63.5}{.75} + 25 = -60 \text{ psi.} \quad (9)$$

Radial bending stress in flange.

$$S'_1 = \frac{6}{h^2}\left(M_o - \frac{1}{2}\, V_o h\right) = \frac{6}{.565}\left(190 - \frac{1}{2}\,(-63.5).75\right) = 2280 \text{ psi.} \quad (10)$$

Maximum radial stress in flange (tension at outer face at junction with cylinder).

$$S'_1 - S_1 = 2280 - 60 = 2220$$

Tangential hoop stress in flange

$$S_2 = \frac{h^2}{4\, t^2}\, T_1(V_o + hp) = \frac{.561}{1.68} \times 21.5(-63.5 + .75 \times 25) \quad (11)$$

$$S_2 = -319 \text{ psi.}$$

(Continued on Next Page)

Cathodic Protection Symposium Scheduled for January

Three Technical articles on methods and experience in underground cathodic protection are scheduled for publication in the January issue's Technical Section.

Tangential bending stress in flange

$$S_1' = S_1 + \frac{0.80}{h^2(d^2-a^2)}\left[d^2\left(-15\,M_o + 7.5\,h\,V_o + 1.492\,P\log_e\frac{b}{a}\right) + .4475\,P\,(b^2-a^2)\right] \quad (12)$$

$$= 2280 + \frac{0.80}{.361\,(193)}\left[593(-15\times 190 + 7.5(.75)\,(-63.5) + 14920\times .1397 + .4475\times 10^4\,(130)\right]$$

$$S_1' = 1708 \text{ psi.}$$

Maximum tangential stress in flange (tension at inner face at junction with cylinder).

$S_2' + S_2 = 1708 + (-319) = 1489$ psi.

All of the calculated stresses are within the allowable 2430 psi.

Based on this analysis the duct system was built with 3/8 inch wall and 3/4 inch thick flanges. Figures 5 and 6 show the testing of various sub-assemblies before acceptance by the customer. Hydrostatic pressures in excess of 25 psig were applied without causing failure of the duct or its flanges. No pieces were tested to destruction, as the short delivery schedule for this project would not have permitted sufficient time to produce extra pieces for destruction tests. However, some degree of confidence in the basic approach was confirmed by the destruction test of a small jacketed vessel. This small pickling vat is shown in Figure 7.

Tangential bending stress in flange

Example 2—Jacketed Vessel

Conditions:

Inner vessel—Hydrochloric acid pickling solution. 5/16 in. minimum wall of glass-reinforced polyester (specified). Service: Pickling, cycle unknown.

Water jacket—Water: 50 psig hydrostatic test. No temperature specified or indicated

Because of the nature of the project, no further information could be obtained at the time. From experience, service expected of the inner shell probably would involve handling warm hydrochloric acid of moderate concentration or possibly full strength acid. Although the function of the water jacket was not given, it could serve only to heat or cool the pickling solution. The most adverse condition would be if hot water were used in the jacket. With the above appraisal in mind, the following values were selected for the reinforced plastic to be employed: (See Table 1).

Inner Shell	Allowable Tensile Strength, psi
(a) Basic, dry, room temperature tensile strength of laminate (as before)	9000
(b) Strength reduce to 35% of basic strength to account for the most severe corrosive service anticipated Case 4 Table 1	3150
(c) Strength reduced to 50% of (b) for mechanical considerations	1575
(d) Strength reduced to 90% of value (c) for variations in production	1420

Modulus of elasticity approximated for this service as 0.7×10^6 psi.

Outer Jacket	
(a) As above	9000
(b) Strength reduced to 33% of basic value for long term exposure to hot water on inside surfaces Table 1 Case (3), averaged with strength reduced on outside surfaces to 75% Table 1 Case (1) and 80% Case (2) $\simeq$ 60%	5400
(c) As above	2700
(d) As above	2430

Modulus of elasticity approximated for this service 0.8×10^6 psi.

Having thus approximated the value of tensile strength allowable for design purposes, conventional stress formulas are employed as follows:

Calculate required wall thickness:

Outer Jacket

$$t = \frac{pR}{s_2} \quad (13)$$

Where:

t = wall thickness (in.)

p = jacket pressure (psi)

R = radius of jacket (in.)

s_2 = hoop stress—tensile (psi)

Max. allowable = 2430 from preceeding paragraph

Substituting: $t = \frac{50(7)}{2430} = .144$ in., or 3/16 in. to the nearest largest sixteenth of an inch.

Inner Shell

$$p' = 0.807\,\frac{E\,t^2}{l\,r}\,\sqrt[4]{\left(\frac{1}{1-v^2}\right)^3\frac{t^2}{r^2}} \quad (14) \text{ Ref. 6}$$

Where:

p' = maximum allowable pressure (psi) at which wall buckling occurs

E = modulus of elasticity (psi)

l = length of shell (in.)

r = radius of shell (in.)

t = wall thickness (in.)

v = Poisson's ratio, approximated as 0.3

(Continued on Page 24)

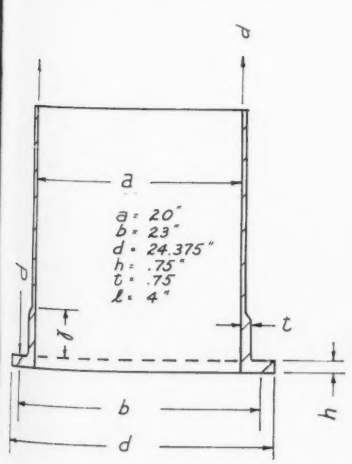


Figure 4—Integral flange.

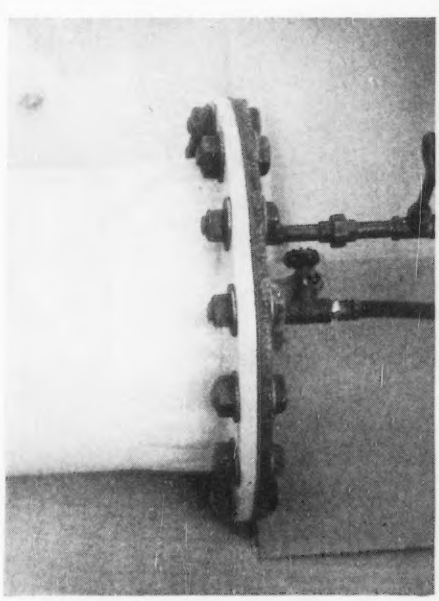


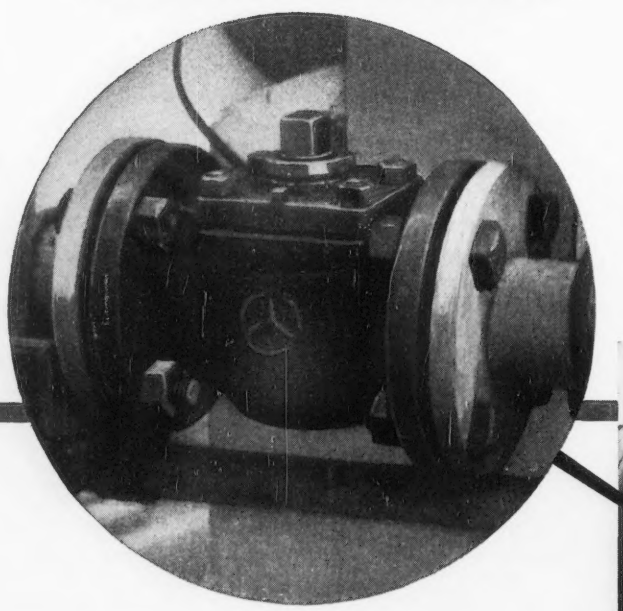
Figure 5—Flange under test.

Figure 6—Hydrostatic pressure testing of duct sub-assemblies.

PENTON® COATINGS

A simple solution to your complex

CORROSION PROBLEMS



Though many corrosion problems may seem complex, a Penton coating can often supply a simple answer. Economically applied to low-cost metal substrates, Penton provides a tough, pinhole-free barrier against corrosion at elevated temperatures.

A typical example is this Penton-coated TUFLINE plug valve, successfully serving in the discharge and filling line of a 20-Baume muriatic acid installation where even expensive metals could not withstand the corrosive exposures involved.

Durable Penton coatings for valves, pipes and fittings, and pump and meter parts ranging in thickness from 10 to 40 mils, can be achieved by various techniques. They provide excellent protection against the corrosive attack of acids, alkalis and solvents, both to exterior surfaces and interior wetted parts.

Penton, chlorinated polyether, is a modern engineering material with an established record of success in combating today's toughest corrosion problems. Easy to mold or fabricate, it can serve as a coating or liner for metal, or be used in solid molded form.

Want to learn more about Penton? Write for your copies of "The ABC's of Penton for Corrosion Resistance," which cites data on Penton's chemical resistance to more than 300 reagents, and "The Penton Buyer's Guide," a complete listing of fabricators and suppliers of Penton processing equipment.

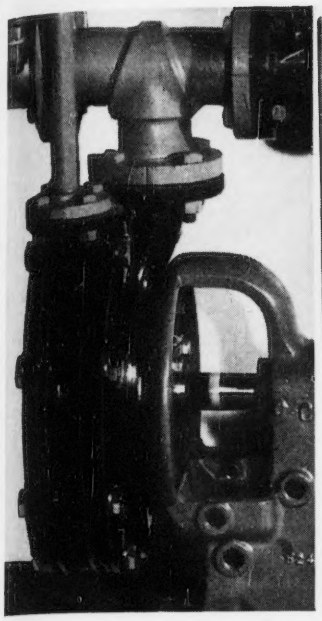
PENTON MAKES TUFLINE VALVES TOUGHER

Tufline valves in sizes from ½" to 2" with a CORVEL*-Penton coating are made by Continental Manufacturing Company, Cincinnati, O. The coating was applied by the WHIRLCLAD* customs coating service of The Polymer Corp., Reading, Penn.

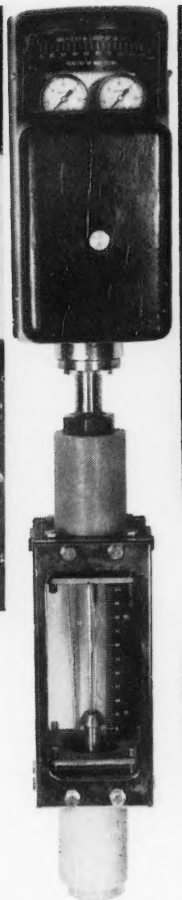
**Trademarks of The Polymer Corp.*

HERCULES POWDER COMPANY
INCORPORATED
Hercules Tower, 910 Market Street, Wilmington 99, Delaware

CP60-13



This pump has a 25 mil Penton coating applied by fluidized bed process to pump impeller and both the inside and outside of pump head, providing internal protection against corrosive fluids as well as an exterior surface finish resistant to corrosive atmosphere.
(PHOTO COURTESY GOULDS PUMPS, INC.)



Flowmeter coated with CORVEL-Penton provides high-order corrosion resistance for use in a wide variety of chemical atmospheres that attack metals.
(PHOTO COURTESY BROOKS ROTAMETER CO.)

Protect your processing equipment from **corrosion** with **CORVEL®-Penton† Coatings**

Iron pipe and flanges coated with CORVEL-Penton on internal and external surfaces.

WHIRLCLAD® Custom Coating Service

CORVEL-Penton provides ideal, high order corrosion protection for valves, pumps, flow meters, pipe and fittings in the chemical, food and other processing industries. Because of their excellent resistance to almost all acids, alkalis, solvents and chlorides, CORVEL-Penton coatings on low cost metals are unmatched in performance and economy . . . competitive in cost with low order corrosion protection.

Penton coatings operate in temperatures to 250°F. and over. The wear and abrasion resistance of the coatings imparts excellent durability to parts operating under corrosive conditions.

In Polymer's WHIRLCLAD custom coating service, Penton is applied to valves, pipes and processing equipment in the WHIRLCLAD coating system‡, utilizing a fluidized bed of dry, finely divided resin powders. The powders heat-fuse to form a uniform, continuous film with thorough coverage of edges, corners and projections on complex shapes. Pin-hole-free coatings are readily obtained in thicknesses of .010" and over. Coatings of vinyl, polyethylene, cellulosic, nylon and epoxy are also available.

- **Nationwide coating facilities**
- **Specialized application techniques**
- **Experienced engineering assistance**

‡The basic fluidized bed process was developed and patented in Germany. Polymer's WHIRLCLAD coating system which encompasses the fluidized bed technique is protected by various apparatus and process patents in the United States and foreign countries and numerous applications are pending. Exclusive patents and licensing rights in the United States and Canada are owned by a subsidiary of The Polymer Corporation.

WRITE FOR BULLETIN CP-1

POLYPENCO® *industrial plastics*

CUSTOM COATING SERVICE
WHIRLCLAD Division
The Polymer Corporation
Reading, Pennsylvania

Other Custom coating facilities: Santa Ana, California
Rolling Meadows, Illinois

†Trademark of Hercules Powder Co.

Reinforced Plastics –

(Continued From Page 21)

Transposing the above formula to solve for wall thickness:

$$t = \sqrt[10]{\frac{p'^4 l^4 r^6}{(0.807)^4 E^4 \left(\frac{1}{1-\nu^2}\right)^2}} \qquad (15)$$

Substituting the above values:

$$t = 0.285 \text{ in.}$$

This is more than ¼ inch, so 5/16 inch wall is specified.

Since shop testing of this fabrication will not be under the actual service conditions, calculation for the inner shell is repeated for the conditions of the test. Thus for hydrostatic pressure of 50 psig, approximate as follows:

	psi
(a) Basic tensile strength	9000
(b) Mechanical factor 50% reduction	4500
(c) Production variations 10% reduction	4050

Modulus of elasticity = 1.0 x 10^6

Substituting in Equation (15):

$$t = .247 \text{ in.}$$

This indicates that a wall slightly less than ¼ inch thick but in excess of 3/16 inch should withstand 50 psig jacket pressure. A vessel was fabricated with the critical wall (inner shell) of 3/16 inch thickness. Substituting for this wall thickness in Equation (14) the inner shell might be expected to withstand the following pressure:

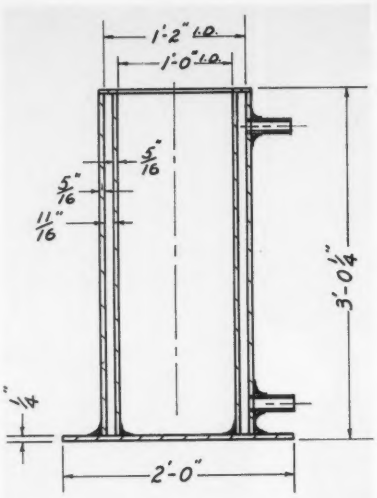


Figure 7—Small jacketed pickling vessel.

$$p' = \frac{0.807 \times 10^6 (0.1875)^2}{36 \times 6}$$

$$p' = 25 \text{ psig}$$

This vessel (with the 3/16-inch thick shell) was subjected to the hydrostatic test and failed before the pressure reached 50 psig. Failure occurred by buckling of the inner shell. The vessel fabricated with the 5/16-inch thick inner shell wall withstood the 50 psig hydrostatic pressure test as the calculations indicate.

Conclusions

The general concept of applying known stress formulae to plastic materials of construction has been employed extensively. Many designs over a period of several years have withstood the tests of actual service conditions in the field. Selection of casually designed plastic equipment or that which has not been analyzed at all, has resulted in failures under service conditions. This can generally be avoided by applying specifications which account for the various factors affecting the design values of the materials employed. It is of great advantage to all concerned if the equipment designer is furnished with complete information concerning the environment and performance of test samples in the environment. By thoughtful analysis of the conditions involved, coupled with the evaluation of the best pertinent data available, proper values for design can be approximated. Use of these values with conventional design techniques can produce plastic process equipment that will stand the test of industrial service.

References

1. I. Katz, and J. Goldberg. *Materials and Methods*, 130, November, 1956.
2. Herron Testing Laboratories, Inc. Report to Heil Process Equipment Corporation, August 2, 1957.
3. Laminac Polyester Resin 4107 Chemical Resistance. American Cyanamid Company, September, 1958.
4. Werren and Heebink. Weathering of Glass-Fabric-Base Plastic Laminates. Forrest Products Laboratories, WADC 55-319, May 1956.
5. J. W. Case. *Materials and Methods*, 114, September, 1956.
6. R. J. Roark. Formulas for Stress and Strain. 3rd Edition 1954. McGraw-Hill Book Company.
7. Atlac 382 in Wet Lay-Up. Atlas Powder Company, Wilmington, Del.
8. American Society of Mechanical Engineers: Rules for Construction of Unfired Pressure Vessels, Sec. VIII ASME Boiler Construction Code, 1956 par UG-27.
9. E. O. Holmberg, and K. Axelson. Analysis of Stresses in Circular Plates and Rings. Applied Mechanics (Am. Soc. Mech. Eng. Transactions), **54**, 1932, APM 54-2, page 13 ff.

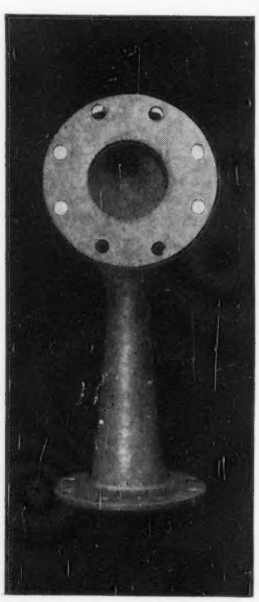
•

The American public buys about $85 billion worth of food a year, including about $200 million worth of gourmet delicacies.

•

Over a million new homes were purchased in 1959 by USA residents at a

Du Verre Completely Controls Corrosion in New S&K Gas Scrubbers



Now du Verre resin bonded fiberglass construction adds superior corrosion resistance to Schutte and Koerting's efficient Ejector-Venturi Scrubbers. Widely used throughout the process industries, SK 4010 units move large quantities of air and gas at low draft. They effectively remove dust and particulate matter, obnoxious vapors and corrosive gases.

Besides complete corrosion control, du Verre construction offers many other important advantages: Unlike lined equipment, venturi and jet can be accurately machined for more efficient operation. Erosive action of the high velocity venturi jet is minimized, even at temperatures approaching 300° F. High strength coupled with low weight eases handling and installation. The need for elaborate supporting steel is eliminated. Complete corrosion resistance on both exterior and interior surfaces eliminates need for painting and maintenance.

Investigate the many advantages of du Verre corrosion-resistant ducts, stacks, hoods, tanks, trays and specially-fabricated process equipment.

Write for Bulletin 101 Today!

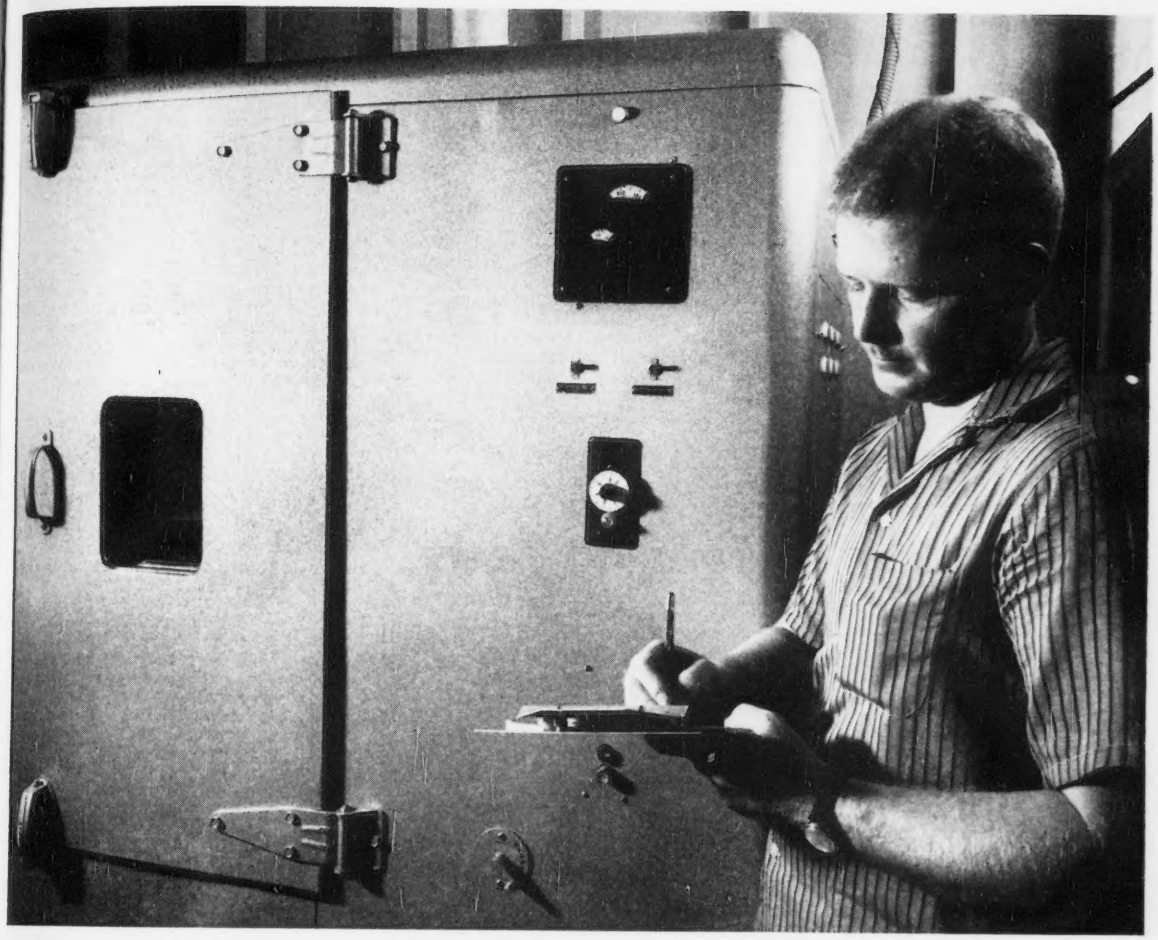
du Verre inc.

du Verre, Incorporated • Box 37-L, Arcade, N. Y.

Color Slide-Talk on 1960 Corrosion Show

A 35-mm color slide show of about 100 slides of exhibits at the 1960 Corrosion Show at Dallas has been prepared and is available for showing at NACE Section meetings. The show, which has a commentary on specific items exhibited, is available on a first-come, first-served basis on application to G. A. Rolak, NACE Central Office.

The show provides an opportunity for NACE members who were unable to visit the Corrosion Show personally to see some of the equipment on display. While the presentation does not include all the exhibits, it will give a good idea of the show. Presentation time should vary between an hour and an hour and a half.



TLC RESEARCH WORKS FOR YOU

New development advances in processing plastic linings for oil field tubular goods are coming from progressive TLC research. New lining techniques, new methods of quality control, new testing devices, new product formulae — all new ideas get a thorough check. Some won't work; but those that do, work better for you because of checks and counter-checks in practical application and subsequent testing.

In tests of new and established lining compounds, a pilot test oven is used to determine the exact temperatures for proper processing for field use. This is just one example of the many methods TLC uses to give research more than lip service, to make it work for you.

T.L.C.®

THE PROOF OF QUALITY

TUBULAR LINING CORPORATION

P. O. BOX 20019 • HOUSTON 25, TEXAS • JACKSON 3-7013

Materials Evaluation Program

Laboratory Screening Tests of *SPRAYED LININGS* for Chemical Process Equipment*

R. S. Foster
Dow Chemical Company
Freeport, Texas

Abstract

Outlines materials evalution program of chemical process company. Gives detailed results of laboratory immersion tests to screen coatings for equipment protection. Tabular data give coatings tested, corrosive agents, duration of tests and interpretation of serviceability of coatings. Also discusses importance of screening tests, environment tests in pilot plant before a coating is used in large scale field use. Gives comprehensive lining cost survey to show relative cost of coatings in comparison to use of clad material, for example. 2.3.4

Introduction

MATERIALS EVALUATION program as conducted by one chemical process company illustrates how many corrosion problems can be solved by proper selection of equipment constructed of materials to withstand the corrosive environment involved with each specific piece of equipment.

If highly corrosive conditions are involved, construction materials best suited for these conditions should be used for the equipment. For example, if temperatures are to exceed 300 F, alloys or claddings should be considered. If temperatures below 300 F are expected and if strong organic solvents are not involved, sheet rubber or vinyl linings should be investigated to protect the equipment and containers, particularly if abrasive slurries are involved. For temperatures below 300 F, however, economic studies indicate that mild steel protected by thin film spray applied linings are the least expensive method of constructing process or storage equipment which handle corrosive fluids.

Spray applied lining materials can be organic or inorganic. Examples of organic types are phenolic or epoxy thermosetting plastic; inorganic examples are zinc silicate or phosphate polymers.

Even though they often are cheaper than alloys or sheet linings, spray applied linings frequently are not used because there is little reliable information on their durability. For this reason, the laboratory investigations described in this article were conducted to obtain accurate information on the durability of these sprayed linings.

Laboratory Testing

Materials to be tested in the laboratory should be chosen after a careful search is made of the technical literature to determine which materials are applicable to the specific problem being considered.

Two methods are commonly used for laboratory testing of materials: lab duplication of the exposure conditions and a simple screening test using minimum conditions.

Laboratory duplication should be as close to actual exposure conditions as possible. Usually a simple apparatus can be set up to simulate process conditions. However, this is not always possible. For example, conditions inside reactors which produce heat sensitive monomers can be reproduced only by making the monomer because such materials quickly polymerize to solids at the reaction temperature.

The second test method, simple screening of linings using minimum conditions, is useful to establish the best type material to use in simulated testing. Small steel panels coated with lining materials generally are immersed in pure samples of the compounds or solvents involved in the exposure. This can be done at ambient temperature to eliminate materials definitely not applicable to the exposure problem.

This screening method is inexpensive, simple to conduct and permits many coatings to be tested at one time. The disadvantage of this method is that there is little or no acceleration of failure over that expected in service and that only pure solvents are used. Preparation and storage of test panels for this method have been discussed previously.[1]

Interpretation of Results

Interpretation of test results can be illustrated by the screening tests conducted by a chemical process company. Table 1 gives the results of the immersion test, showing the coating types tested, the corrosive agent each type was exposed to and rating given after exposure. Table 2 gives a summary of the test results showing that 47 different coatings of eight distinct types were evaluated in 314 individual exposures.

Although most coatings were tested only in those solvents for which they were recommended, less than half of the tests indicated serviceability. Epoxy coatings seemed to have the widest range of application of those materials tested. Coal tar epoxy coatings exhibited surprising resistance to some strong acids such as HCl and 50 percent H_2SO_4. The polyurethanes showed good resistance in chlorinated solvents such as perchloroethylene. Few vinyl or phenolic coatings were included in this test because their properties had been determined previously. Baked phenolic coatings showed excellent resistance to a wide range of chemicals and solvents.

Time duration of individual tests is given in Table 3. From the 314 tests, 86 panels were graded excellent, 60 good, 29 poor, 46 failures and 94 graded as complete failure (any coating which failed in less than 30 days). Those coatings graded excellent generally had withstood immersion for more than a year.

The average duration of tests that indicated "good" results was 237 days. Average test duration for failures was 142 days. Omitting those panels with a grade of poor because no interpretation has been made of this grade, the average test duration indication serviceability was 337 days compared with an average of 51 days for tests indicating non-serviceability.

The important items to note are that coatings which are entirely unsuited for a particular environment usually will fail within 7 days and that an exposure of four to five months will indicate most of the failures.

The 24 chemicals and solvents used as test environments in this screening procedure are listed in Table 4. Chemicals and solvents chosen have caused corrosion or product contamination problems at one time or another. Also listed are the total number of linings evaluated in each solvent and the number and type of linings found to be worthy of further testing. Most aggressive chemicals tested were acrylic acid, concentrated HCl, 30 percent nitric phenol and concentrated H_2SO_4. Most aggressive solvents were acrylonitrile, chloroform, methylene chloride and styrene.

Pure chemicals and solvents were used for this reason: there are many possible combinations of these chemicals and solvents. To test all such combinations would be impractical. If a lining fails in contact with any one solvent used in a mixture of solvents, the lining probably will fail when exposed to the mixture. Thus, a screening test can eliminate many potential failures at the secondary testing stage. However, this stage is necessary because many times a lining will be resistant to individual solvents in a mixture but not to the mixture.

One of the most important variables in the secondary testing stage is temperature. For example, service life of the best coating exposed to 73 percent NaOH was reduced from 840 days at 225 F to only 340 days at 265 F. This indicates a reduction in coating life of 12.5 days per degree of temperature rise. Vapor pressure of many acids and solvents increases rapidly at temperatures above ambient; consequently, failures in the vapor space above normal liquid levels can become a problem as temperatures increase.

Important Sequence of Tests

Extrapolation of test data should be done one step at a time: from screening tests to simulated environment test to small tests in pilot plant or production equipment and then to large scale field

(Continued on Page 28)

★Revision of a paper titled "Laboratory Testing of Spray Applied Lining Materials" presented at the 16th Annual Conference, National Association of Corrosion Engineers, March 14-18, 1960, Dallas, Texas.

TABLE 1—Immersion Test Results (Time in days at 70 F)

COATINGS RESIN TYPE	Water H_2O Distilled	Sulfuric Acid H_2SO_4 Conc.	Sulfuric Acid H_2SO_4 50%	Styrene C_8H_8	Sodium Hydroxide NaOH 50%	Propylene Glycol $C_3H_8O_2$	Phenol C_6H_6O	Perchloroethylene C_2Cl_4	Nitric Acid HNO_3 30%	Methylene Chloride CH_2Cl_2	Methyl Chloroform $C_2H_3Cl_3$	Iso-propyl Alcohol C_3H_7O	Hydrochloric Acid HCl 10%	Hydrochloric Acid HCl Conc.	HNO_3 40% HF 5%	Glycerol $C_3H_8O_3$	Ethylene Glycol $C_2H_6O_2$	Ethylene Dichloride $C_2H_4Cl_2$	Chloroform $CHCl_3$	Carbon Tet. CCl_4	Benzene C_6H_6	Allyl Chloride	Acrylonitrile C_3H_3N	Acrylic Acid
1. Chlorosulfonated Polyethylene																								
A	G-116	CF-3	F-116		E-116				CF-3					CF-3										
B	P-116	CF-11	G-116		E-116				CF-3					CF-3										
C	F-116	CF-3	F-116		E-116				CF-3					CF-3										
D	P-116	CF-3	G-116		CF-3				CF-3					CF-3										
2. Coal Tar Epoxy																								
A			E-347		E-347								CF-21							G-347				
B			E-300		E-349					CF-11				G-208			E-300			CF-1				
C				F-64	E-205			CF-1		P-205	P-205							CF-1		P-205	F-64			
D	E-346		E-346		E-347		CF-1				CF-1			F-60	CF-4			CF-1	CF-1	CF-1				
3. Epoxy																								
A Cat.	F-105		G-300	CF-21	E-556	G-30	CF-3	CF-7		CF-1	E-300	E-337				E-300	E 556	CF-7	CF-1	E-556	F-7	CF-1	F-48	CF-1
B Baked				F-68	E-68			G-68			CF-1	F-337					E-68	CF-1		E-68	F-68	G-130		
C Baked				E-556	E-556	G-92											E-556	CF-30		E-556	E-556			
D Cat.								P-700		P-1005						E-899			P-218	F-121				CF-1
E Cat.						E-1005					E-1005					E-899	E-1005	P-218						
F Cat.				G-59						P-66	E-66						E-66	P-66		E-66	E-66			
G Cat.			G-300	CF-11													G-300			F-34		CF-1		
H Cat.						E-919		E-920		CF-3	G-920					E-899	E-919	F-919	CF-3	P-390				
I Cat.						F-442		P-442		F-42	P-121						E-1005	F-442	CF-14	F-121				
J Baked			F-137	P-137			CF-3			G-300					CF-4			G-300		G-141		G-18		
K Cat.			F-137	P-137						G-300							E-300			F-109		CF-1		
L Baked			P-300	CF-30						F-34							E-300			E-300				
M Baked																E-899							G-366	
N Baked																								
O Cat.				G-7	P-556			E-7		G-7							E-7	G-7	CF-7	E-556	F-556			
P Cat.					E-556			E-7		CF-1							G-556	CF-1	CF-1	E-556	G-7			
4. Furan	E-146		E-146	E-146	E-146			G-146					E-146	CF-14						F-146	CF-14			
5. Phenolic																								
A Baked										E-347					CF-5	E-899		E-347	E-347			G-33		E-52
B Cat.	E-346		E-300				CF-3			CF-1				CF-20	CF-1		E-300			E-300			CF-3	CF-3
C Cat.			CF-30	CF-1						CF-1							E-300			F-109				
D Cat.																E-899								
E Cat.										P-1005									P-964					
F Cat.										CF-1									CF-1					
G Cat.										CF-1									CF-1	E-963				
H Cat.										E-175						E-899			F-60	G-963				
6. Polyurethane																								
A	P-270			E 270	G-238		CF-1	G-369		CF-1			F-98	CF-1				F-50	F-50	G-353	E-270		E-264	CF-1
B					G-238			F-36					CF-14					CF-1		F-36				
C					G-238			G-369					F-50					CF-1		F-83				
D	G-65			F-270	G-238		CF-1	G-369		CF-1			G-238	CF-1				CF-1		G-83	CF-1		CF-1	CF-1
E	E-270			P-270	F-83		CF-1	G-369		CF-1			G-238	CF-1				G-238		F-90	E-270		E-264	CF-1
F					G-238			G-369					G-238					F-50		F-58				
G					G-238			G-369					F-36					G-384		F-50				
H					F-36			G-369					G-58					G-369		G-369				
I					F-36			G-369					G-58					G-369		G-369				
7. Vinyl																								
A			E-300				CF-30							CF-20		E-899	E-300					CF-1	CF-16	
B	E-346		F-162				CF-3							CF-20	P-13	E-300	E-300					CF-1	CF-30	
8. Inorganic																								
A							G-60																	
B			CF-3	E-409			F-300	G-300		E-300	E-300						P-141	P-300	E-300	G-257	E-521		F-164	
C			CF-2	G-60	CF-7	P-300	F-300	G-60		E-300	E-300						CF-7	P-300		F-141	G-60			

E—Excellent G—Good P—Poor F—Failed CF—Complete Failure Blanks indicate no tests conducted. Letters under coating types indicate different brands and formulations tested.

Sprayed Linings –

(Continued From Page 26)

use. It can be argued that often there is not enough time for this procedure to be used, that the design groups have to make an immediate recommendation or specification before all the tests can be conducted. On the other hand, few processes get from the laboratory bench to production plant in less than five years, so materials of construction should have been determined well in advance of the final design stage.

In this sequence of tests, it should be understood that laboratory immersion tests are not necessarily accelerated tests. Extensive lab tests on coatings for use in caustic tank cars indicate that the acceleration factor is between 1 and 1.5. In other words, test coatings applied in tank cars lasted only a little longer than they did in the simulated laboratory tests. Temperature may be used as an effective means of accelerating film breakdown. Higher temperatures give greater acceleration factors.

Lining Costs Survey

A comprehensive lining cost survey is given in Tables 5 and 6. These calculations are based on several assumptions and limitations; therefore, they should be used only as approximations. For example, these figures are for field fabricated and lined vessels of greater than 10,000 gallons capacity. Production line produced vessels would cost considerably less. Also, these tables are based on labor and material costs (1958-59) in the Gulf Coast area and may not be representative of other parts of the country.

Table 5 shows the unit material cost per square foot. Table 6 gives the cost of steel plate backing in the case of lined surfaces and cost of fabrication. Table 5 compares the cost of each material with the cost of 8/8-inch steel plate. For example, if 3/8-inch mild steel costs one dollar per square foot, then 1/16-inch nickel clad would cost

(Continued on Page 32)

TABLE 2—Results of Solvent Tests

Coating Type	Number of Materials Evaluated	Number of Tests	Percentage Serviceable
Chlorosulfonated polyethylene	4	24	25
Coal tar epoxy	4	28	39
Epoxy (catalyzed and baked)	16	109	52
Furan	1	9	66
Phenolic	8	33	49
Polyurethane	9	70	49
Vinyl	2	16	38
Inorganic	3	25	52
Total	47	314	Average 47

TABLE 3—Time Duration of Tests

Grade	Number of Tests	Average Duration of Tests (days)	Rating	Average Test Duration for Each Group (days)
Excellent	86	408	Serviceable	337
Good	60	237		
Poor	29	310	.....	
Failure	46	142	Not serviceable	51
Complete failure*	94	7		

*Coatings which failed in less than 30 days.

TABLE 4—Tabulation of Test Results

Solvents Tested	No. of Linings Tested	No. Service-able	Type of Linings Recommended for Further Study
1. Acrylic Acid	7	1	Baked phenolic
2. Acrylonitrile	9	3	Baked epoxy, polyurethane
3. Allyl chloride	8	3	Baked phenolic, baked epoxy
4. Benzene	13	7	Silicate, baked epoxy, polyurethane
5. Carbon tetrachloride	33	17	Silicate, cat. epoxy, polyurethane
6. Chloroform	14	2	Silicate, baked phenolic
7. Ethylene dichloride	24	6	Baked epoxy, baked phenolic, polyurethane
8. Ethylene glycol	19	17	Cat. epoxy, vinyl
9. Glycerol	10	10	Cat. epoxy, vinyl
10. HCl, conc.	12	1	Coal tar epoxy
11. HCl, 10%	11	4	Coal tar epoxy, polyurethane
12. Isopropyl alcohol	2	1	Cat. epoxy
13. Methyl chloroform	10	5	Silicate, cat. epoxy
14. Methylene chloride	24	6	Silicate, baked phenolic
15. Nitric acid 30%	4	0	.....
16. Nitric —40% +HF 5%	6	0	.....
17. Perchloroethylene	20	15	Silicate, polyurethane, cat. epoxy
18. Phenol	12	1	Silicate
19. Propylene glycol	6	4	Cat. epoxy
20. Sodium Hydroxide 50%	25	18	Cat. epoxy, coal tar epoxy, hypalon
21. Styrene	17	6	Silicate, polyurethane, baked epoxy
22. Sulfuric acid 50%	19	10	Coal tar epoxy, cat. epoxy
23. Sulfuric acid, conc.	4	0	.....
24. Water (distilled)	13	7	Vinyl, coal tar epoxy

TABLE 5—Comparative Cost of Alloys, Claddings and Linings

Material	Unit Applied Cost per Square Foot
A. 3/8-inch carbon steel plate	1.0
B. 3/16-inch rubber sheet lining	2.2*
C. 3/32-inch vinyl sheet lining	2.6*
D. 1/16-inch 304 stainless steel clad	4.0*
E. 1/16-inch nickelclad	7.9*
F. Sprayed linings	
1. Baked phenolic	1.0*
2. Vinyl linings	0.8*
3. Zinc silicate	0.4*
4. Catalyzed epoxy	0.4*

*Does not include cost of carbon steel backing for linings or claddings.

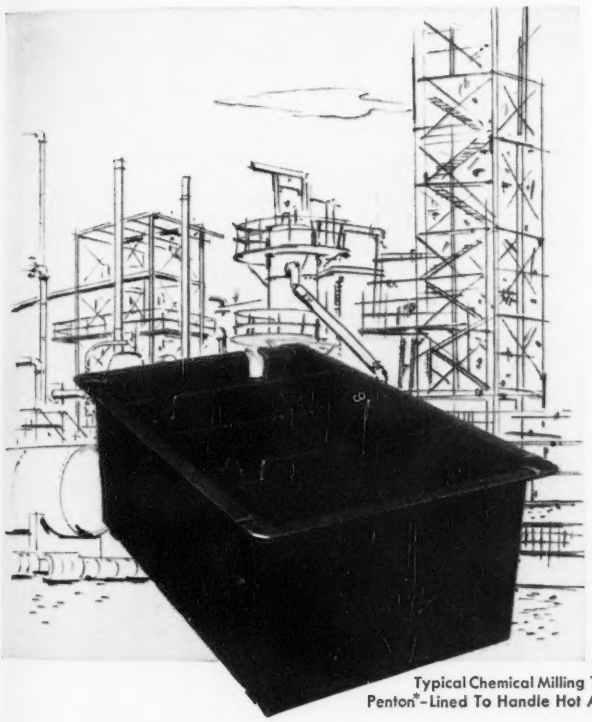
TABLE 6—Capitalized Cost Comparison* of Fabricated Vessels[2]

Material of Construction	Esti-mated Service Life (Years)	Unit Capital-ized** Cost per Square Foot	Order
3/8-inch carbon steel plate	3	1.0	2
Carbon steel plus catalyzed epoxy lining	5	0.8	1
Carbon steel plus baked phenolic lining	5	1.1	3
Carbon steel plus 3/16-inch rubber lining	10	1.0	2
Carbon steel plus 3/32-vinyl lining	10	1.2	4
Carbon steel plus 1/16-inch 304 stainless	15	1.3	5
Carbon steel plus 1/16-inch nickel clad	15	2.0	6

*Capitalized cost is the first cost plus present value of an indefinite number of renewals.
**Based on cost of carbon steel as one unit.

GAR-LINE PENTON TANK LININGS

for Corrosion Resistant Service



Typical Chemical Milling Tank Penton*-Lined To Handle Hot Acids

New GAR-LINE Penton Tank Linings offer economical, high-temperature protection against corrosion. Where only more expensive materials were previously used, GAR-LINE Penton Tank Linings are proving their ability to perform as well as—and better—in many corrosive exposures at high temperatures.

Unique Properties. Mechanically, GAR-LINE Penton Tank Linings exhibit excellent tensile strength at high temperatures, good dimensional stability and low water absorption . . . Chemically, they resist all inorganic acids except fuming nitric and fuming sulfuric.

Applied by carefully selected and authorized applicators. The experience of these tank lining experts guarantees satisfactory GAR-LINE Penton installation, prevents expensive failure due to improper application. Approved applicators include:

ABRASION & CORROSION ENGRS.
1205 N. McMasters Street
Amarillo, Texas

AUTOMOTIVE RUBBER CO., INC.
12580 Beech Road
Detroit 39, Michigan

BARTHEL CHEMICAL CONST., CO., INC.
P.O. Box 1025
Tacoma 1, Washington

BELKE MFG. CO., INC.
947 N. Cicero Avenue
Chicago 51, Illinois

BITTNER INDUSTRIES, INC.
91 Diaz St.
P.O. Box 10265
Prichard, Alabama

BUCKLEY IRON WORKS
21 Christopher Street
Dorchester, Mass.

BUFFALO LININGS
73 Gillette Avenue
Buffalo 14, New York

CHEMICAL PROOF OF SEATTLE
625 Alaska Street
Seattle, Washington

ELCHEM ENGRG. & MFG. LTD.
2025 James Street
Burlington, Ontario, Canada

ELECTRO CHEMICAL ENGRG. & MFG. CO.
750 Broad Street
Emmaus, Pennsylvania

THE FORTUNE COMPANY
1906 N. Mosley
Wichita 14, Kansas

GOODALL RUBBER COMPANY
2050 N. Hawthorne Avenue
Melrose Park, Illinois

HANSZEN PLASTICS COMPANY
835 S. Good-Latimer Expressway
Dallas, Texas

INNER-TANK LINING CORP.
4777 Eastern Avenue
Cincinnati 26, Ohio

MAURICE A. KNIGHT
Kelly Avenue
Akron 9, Ohio

MERCER RUBBER CORPORATION
Highway 46, Cor. Huyler
Little Ferry, N. J.

METALWELD, INC.
Scotts Lane & Abbottsford Rd.
Philadelphia 29, Pa.

PARKER BROTHERS, INC.
7044 Bandini Blvd.
Los Angeles 22, California

PLASTIC APPLICATORS INC.
7020 Katy Rd.
P.O. Box 7631
Houston 7, Texas

RUBBER MILLERS, INC.
707 S. Caton Avenue
Baltimore, Maryland

ST. LOUIS METALLIZING CO.
625 S. Sarah Street
St. Louis 10, Missouri

STEBBINS ENGRG. & MFG. CO.
Watertown, New York

GARLOCK

Investigate GAR-LINE Penton Tank Linings as the answer to your corrosion problems. For more information, contact the applicator nearest to you. Or, write for data on Penton; information also available on Teflon Anti-Stick and Teflon† Tank Linings. Special Products Dept., Garlock Inc., P.O. Box 612, Camden 1, New Jersey.

*Registered Trademark, Hercules Powder Company
†Registered Trademark, The DuPont Company

6⅝″ O.D. X-TRU-COAT SOLVES A CORROSION PROBLEM 22 MILES LONG...

PETROLEUM EXPLORATION COMPANY, Lexington, Kentucky, chose new 6⅝″ O.D. X-TRU-COAT for the job of bringing natural gas to London and Corbin, Kentucky.

The 22-mile pipeline travels cross country through swamps and soils too tough for ordinary protection. X-TRU-COAT is immune to Kentucky's highly acidic soil. What's more, the high-density polyethylene coating seals out electrolytic action. It is extruded end to end over "live" undercoating that eliminates the threat of underfilm migration.

Rate of installation? Petroleum Exploration Company averaged 6600 feet per day. They experienced virtually no damage from shipping, stringing, or backfilling.

New 6⅝″ O.D. and 8⅝″ O.D. X-TRU-COAT can solve a greater number of your oil and gas distribution problems. To make this plastic-coated line pipe even more useful, you can have it in light wall thicknesses—1″ through 4″ nominal—for low pressure gathering and distribution systems.

For information or quotations on the complete package—X-TRU-COAT, X-TRU-TAPE Polyethylene Joint Wraps, and X-TRU-PRIMER—call your nearest Republic representative or mail the coupon on the following page. X-TRU-COAT is produced under the Dekoron® Process.

REPUBLIC STEEL

CLEVELAND 1, OHIO

World's Widest Range of Standard Steels and Steel Products

CATERPILLAR

Sprayed Linings –

(Continued on Page 28)

$7.90 while a catalyzed epoxy lining would cost only 40 cents per square foot applied.

Table 6 shows the capitalized cost of various lining systems including steel plate, lining, fabrication, etc. This method of figuring costs determines what a given piece of equipment will cost to build and to keep in service indefinitely. A service life for each alternate must be assumed. In this case, it was assumed that a corrosive condition existed such that an unprotected steel vessel would have to be replaced every three years. It also was assumed that a spray applied epoxy or phenolic lining would extend this life by two years, making the service life five years.

Based on these assumed service lives and using the capitalized cost of a steel vessel as unity, it was found that lining the vessel with a spray applied catalyzed epoxy would be cheaper than to let the vessel corrode. However, other materials of construction were found to cost more in the long run than unprotected steel. Even if the nickel clad vessel lasted 15 years, it would be twice as expensive as unprotected vessel lasting only three years.

For greater accuracy, other factors such as inflation, maintenance costs, shutdown cost and obsolescence can be included. A vessel lined with catalyzed epoxy coating probably would have a higher maintenance cost than the nickel clad vessel. On the other hand, the possibility of obsolescence would be much greater with the clad vessel.

Summary of Test Results

1. Lining materials to be used in aggressive environments must be thoroughly tested before applications are made in the field.
2. Laboratory immersion tests should be continued for at least four months to give reliable results.
3. Linings probably will last about the same length of time in service as in laboratory unless the laboratory tests are accelerated purposely.
4. Temperature is an important variable in testing linings.
5. Baked organic linings cost approximately twice as much as air dried organic or inorganic linings in field application.
6. Spray applied lining materials can be used in many processes with decided economic advantage over other materials of construction.

References

1. R. S. Foster and V. B. Volkening. A Resume of Procedures for Testing and Evaluating Chemical Resistance Coatings and Linings. *Corrosion*, **15**, 85 (1959) October.
2. T. C. Jelen. Next Time Use Capitalized Cost. *Chem. Eng.*, (1954) February.

DISCUSSIONS

Questions by DuWayne Christofferson, Chicago, Illinois:

1. Why the wide cost spread between spray applied vinyl linings and catalyzed epoxies? Is the problem one of more coats of vinyl, more difficult application or what? I had not thought of the vinyls requiring force drying to any great extent more than the epoxies.
2. Were catalyzed epoxies included in your distilled water immersion test where only vinyls and coal tar epoxies were listed as satisfactory?

Reply by R. S. Foster:

1. The unit applied cost of vinyl linings was estimated to be about two times that of catalyzed epoxy linings. This difference in cost is due primarily to higher application costs for vinyl coatings, extra coats and force dry, but also to somewhat higher material cost in cents per mil per square foot.
2. Yes, catalyzed epoxy coatings were included in the distilled water immersion test, but unfortunately only one coating of this type was tried. It failed after about three months' exposure.

Questions by Walter H. Burton, Allied Chemical Corp., Camden, New Jersey:

Has any work been done to obtain differences in performance of these materials on various steels and do you maintain a stock of identified reproducible steel panel material to insure accuracy of test results in future tests for comparison with past results?

Reply by R. S. Foster:

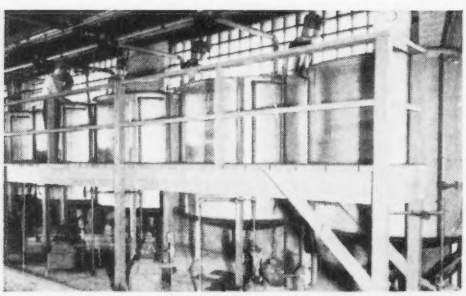
No work has been done along these lines. We use test panels cut from hot rolled mild steel. Usually we try to secure enough panels cut from one steel plate to last through any particular test series. This varies from one to two hundred panels.

•

American supermarkets serve 200 million customers each week and stock an average of 8000 items.

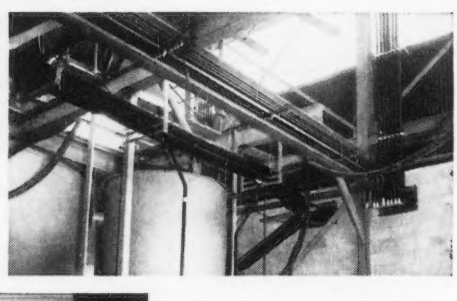
Investigate these Republic products on the basis of

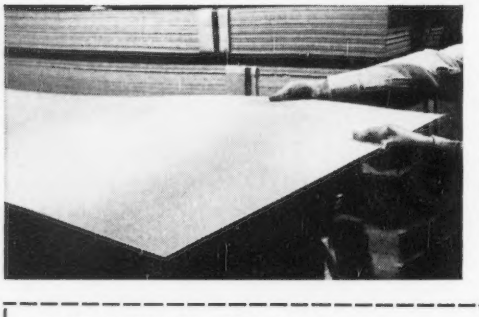
CORROSION RESISTANCE



ENDURO® STAINLESS STEEL provides vital protection against stock loss due to contamination. Available from Republic in more than 40 standard types, this quality stainless steel ably resists most chemicals and chemical compounds. Mail coupon for details.

PLASTIC-COATED E.M.T.— Republic's "Dekoron®-Coated" E.M.T. — outlasts standard conduit by up to ten to one in corrosive atmospheres. Tough polyethylene plastic is applied end-to-end on strong but lightweight ELECTRUNITE® E.M.T. or on Republic Rigid Steel Conduit. Send for information.





CONTINUOUS GALVANIZED SHEETS produced by Republic are known for easier fabrication. Galvanized coating is exceptionally uniform and tight—won't crack, flake, or peel under any forming operation permitted by the base metal itself.

REPUBLIC STEEL

REPUBLIC STEEL CORPORATION
DEPT. CC-1279
1441 REPUBLIC BUILDING,
CLEVELAND 1, OHIO

Please send more information on:
☐ X-TRU-COAT
☐ Stainless Steel
☐ "Dekoron-Coated" E.M.T.
☐ Galvanized Sheets

Name_____ Title_____
Company_____
Address_____
City_____ Zone____ State____

Characteristics, Testing and Some Design Considerations Applicable to Glass Reinforced Plastic Pipe

Figure 2—Facilities for testing plastic pipe.

R. M. Levy

Esso Research and Engineering Company

Linden, N. J.

Abstract

Discusses types of plastic pipe: thermoplastics and thermosets, their glass properties, tensile strength, elastic limits, thermal conductivity coefficient and specific gravity. Also describes resins used. Properties of glass reinforced plastic pipe covered include operating conditions, corrosion resistance, weight, flow characteristics, antifouling characteristics, heat transfer and pipe strength. Describes the pulsating pressure, sustained pressure (stress-rupture) and other tests conducted to determine bond strength between plastic and glass in terms of pipe performance. Also discusses possible applications for the pipe. 6.6.8, 7.2

WHILE THE growth of the plastics industry and the use of plastic pipe is phenomenal, glass reinforced thermosetting pipe has remained relatively unexploited.

There are many characteristics of glass reinforced plastic pipe which make its use attractive. These include corrosion resistance, light weight, good flow characteristics, resistance to paraffin deposition, low thermal and electrical conductivity, non-contamination of product, and ease and economy of installation.

This discussion deals mainly with types of plastic pipe, their characteristics, test methods and applications.

★Presented under the title "Glass Reinforced Plastic Pipe" at a meeting of the Canadian Region, Western Division, National Association of Corrosion Engineers, Calgary, Alberta, Canada, February 11-13, 1959.

Types of Plastic Pipe

Because plastics generally fall into one of two distinct divisions, each with its own general properties, it is no more descriptive to refer to plastic pipe than it is to talk of metal pipe. Specifications and references should be made to the particular generic type of plastic and if possible, to the trade designation also because frequently manufacturing techniques and formulations affect final properties appreciably. Table 1 lists various types of plastics commonly found in piping and tubing. Differences between the divisions —thermoplastic and thermosetting—are discussed briefly.

Thermoplastics

The thermoplastics are softened by heating and when remolded to any given form retain essentially all original properties when restored to original temperature. Major types presently being used in the manufacture of pipe are polyethylene, polyvinyl chloride, butyrate and a styrene-rubber alloy.* Polypropylene also appears promising as a pipe material.[1]

Thermoplastics generally lack resistance to organic solvents but have good resistance to inorganic corrosive solutions. Head loss, due to wall friction, is less than in steel and there is less chance of deposition and subsequent plugging. Light weight makes for ease of handling and installation.

* Kraloy.

(Continued on Page 34)

Plastic Pipe—

(Continued From Page 33)

On the other hand, thermoplastic pipe is limited to low pressure service. Use at temperatures over 150 or below 40 F generally is not recommended. It is susceptible to cold flow and consequently must be supported almost continuously to prevent excessive deflection. In addition, it has a high coefficient of thermal expansion—in the order of ten times that of steel.

Thermosets

Thermosetting plastics set or harden under heat to a final form which cannot be changed upon reheating. Presently, three types are being used in pipe manufacture: Polyester, epoxy, and phenolic. A new thermosetting resin* appears promising.

Because the resins used generally are brittle and low in tensile strength, reinforcing is required. Reinforcing usually is in the form of glass fibers, although cotton, sisal, paper, asbestos, glass cloth and mat, and organic fibers have been used in making composite sections.

TABLE 1—Types of Plastic Pipe and Tubing

Thermoplastic	Thermosetting
Acrylic	
Celluloses	Epoxy
Fluorocarbons	Furan
Polyamide	Phenolic
Polyethylene	Polybutadiene
Polypropylene	Polyester
Polystyrene	Melamine
Polyvinyls	Silicone

The use of thermoplastic pipe has been well established by the many miles of pipe now in service. However, thermosetting pipe which is stronger, can be used at higher pressures, and temperatures and has a wider range of applications than thermoplastic pipe.

Since most thermoset pipe being produced or in development is of glass-reinforced epoxy resin, the pipe specifically referred to in the remainder of this discussion is of this type, although much reported is applicable to polyester and other thermosetting pipe as well.

Pipe Characteristics

Glass reinforced pipe generally is composed of two or three materials—glass fibers, plastic matrix, and an inner liner. Glass Fibers which comprise about 60 to 80 percent of the pipe material are used as a structural cage, and carry the major part of the load. Damage to these fibers can cause serious loss of strength. The glass fibers are held in place by a plastic matrix whose structural function is mainly one of stress transfer. Most pipes have an inner liner of either PVC or epoxy.

There are several manufacturers of glass reinforced plastic pipe, each using a different method of fabrication. They roughly fall into two types—external mandrel wrapping and internal mandrel casting.[2] The external mandrel wrap pipe is made of winding resin impregnated glass fibers around a polished mandrel and subsequent curing with heat. In the internal mandrel process, the glass and resin are preplaced inside a mandrel and cast by use of centrifugal force and heat.

* Buton, Trademark of Enjay Chemical Co., formerly called C-oil.

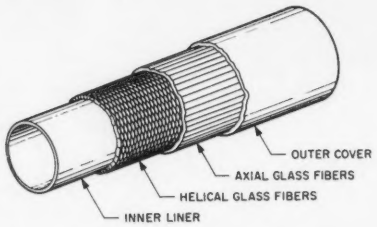


Figure 1—Typical glass reinforced plastic pipe.

In both cases, the glass fibers can be oriented in any direction to provide maximum strength in the direction of maximum load. Usual design for line pipe calls for twice the strength in the circumferential direction as in the axial direction. However, for unusual service conditions—well tubing, for instance—the orientation of the glass can be changed to give greater strength along the desired axis; the longitudinal one in this case. Figure 1 shows a cutaway of a typical externally wound pipe, although for any particular manufacturer minor differences are present; some have no outer cover or inner liner, and glass orientation may differ.

Glass Properties[3]

Glass fibers commonly used in reinforcements are made of a borosilicate type of glass commonly referred to as "E" glass. The glass fiber when drawn is of the order of 0.0002-inch in diameter; 204 are usually drawn together to make a strand or end. Twenty to sixty ends are then drawn together to form a roving for the pipe manufacture. Some of glass properties in this form are discussed below:

a. **Tensile Strength**—Single filaments of "E" glass, under strict laboratory conditions have shown strengths of 1 million psi. Under less strict circumstances, laboratory strengths of 400,000 psi are obtained. However, 200,000 psi is probably as high as one can expect from commercial glass as received from the manufacturer. Further handling, before the final product is formed, could reduce this value to 100,000 psi. Laboratory tests on glass reinforced pipe show the glass invariably sustains 100,000 psi.

b. **Elastic Limit**—The elastic limit value is the same as its ultimate strength; in other words, it possesses true elasticity with no yield. At rupture, elongation is about 3½ percent.

c. **Coefficient of Thermal Conductivity**—The low capacity of glass to transfer heat is, of course, well known. The coefficient of thermal conductivity is about 0.06 BTU/ft.²/hr./°F./ft.

d. **Specific Gravity**—Glass generally is considered a light-weight material with a specific gravity of 2.55.

Resins

Resins used vary among pipe manufacturers. Their properties may differ according to resin suppliers, formulation, cure cycles and many other variables. Furthermore, the properties of cast resins are not necessarily representative of their performance in the reinforced plastic structure. Consequently, no attempt will be made to discuss resin properties here because much has been published in recent years.

However, note that the resins display considerable resistance to chemical attack, probably more so than do a coated or lined metallic pipe. This difference results from necessary modifications made to the basic resin to make it workable as a surface coating.

A new thermosetting resin recently developed is an all hydrocarbon resin, based on a butadiene-styrene copolymer.* This cured resin exhibits high strength, good chemical resistance, high heat stability and extremely low water absorption characteristics. Its hydrophobic nature makes its use in water applications, such as pipe, extremely attractive. As discussed later, water attack on the glass-resin bond is one of the main contributing factors to premature failure. Currently in pilot plant production, this new resin is expected to have an introductory cost less than either epoxies or polyesters.[4]

Pipe Properties

a. **Operating Conditions**—There are no standard schedules in glass reinforced plastic pipe as there are for steel pipe, although the trend is toward standardization on iron pipe OD sizes. The plastics are rated by each manufacturer for his particular product. At present, some maximum long term operating pressures for 2-inch diameter pipe, recommended by the various manufacturers are 1000 psi at 120 F, 1500 psi at 150 F, 1200 psi at 150 F, and 550 psi at 130 F.

Maximum continuous operating temperatures recommended vary from 150 F to 300 F depending on manufacture. In all cases, when operating at these higher temperatures, pressures must be substantially reduced from the maximum listed. On the lower end of the scale, glass reinforced thermoset plastic pipe shows to an advantage because it will retain its strength at temperatures as low as —50 F.

b. **Corrosion Resistance**—The outstanding advantage of plastic pipe is its corrosion resistance: it is immune to the usual corrosion mechanism of electrochemical attack. Superior chemical resistance enables it to withstand exterior and interior attack. Furthermore, there is no danger of contaminating the fluids carried with corrosion products, or traces of metals.

However, chemical attack on the plastic may result in contamination. In most cases, though, this chemical attack also results in the deterioration of the pipe and thus represents a misapplication. Chemical attack on the plastic material in the pipe is usually of the "go or no-go" type. Either the attack is suffered rapidly or the plastic is completely resistant.[5]

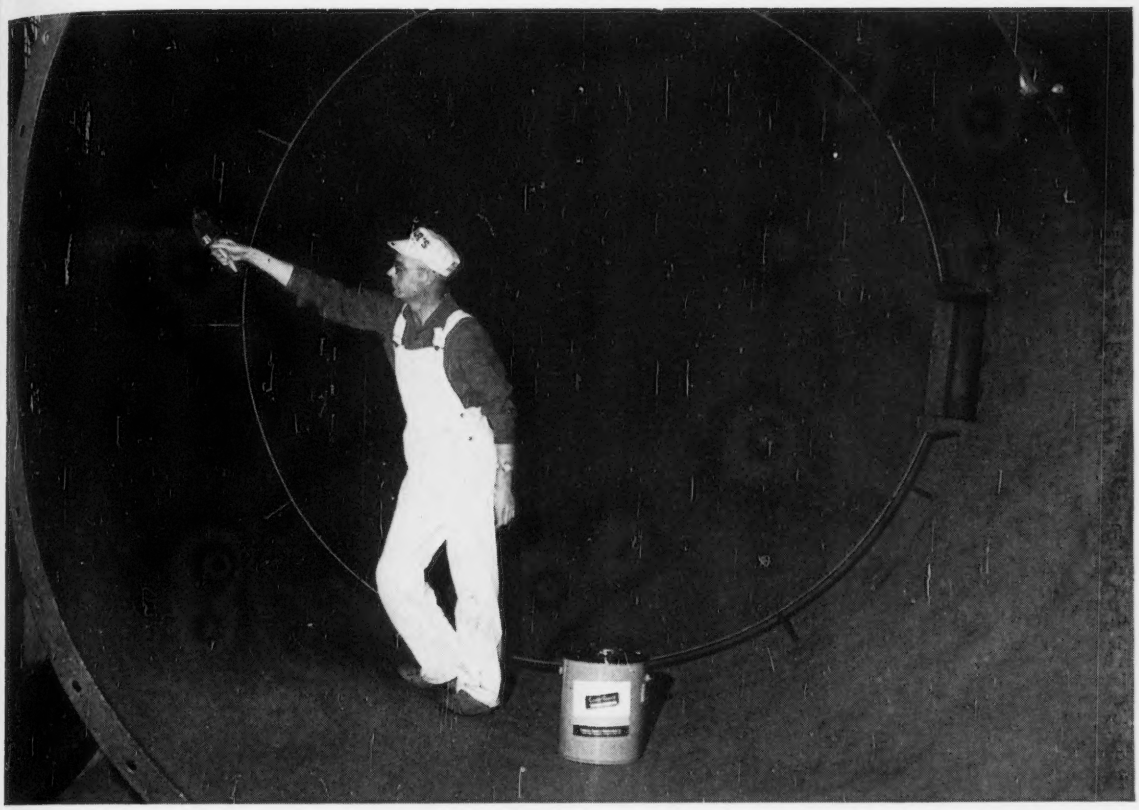
On the other hand, attack on the glass reinforcing or at the glass-resin interface is a more gradual type of degradation. Time usually is required for the reagent to reach the glass and then attack a sufficient amount of glass to cause failure. As discussed later, a common reagent which attacks glass in this manner is water.

Table 2 lists a few demonstrated uses of glass reinforced plastic pipe in corrosive fluids.

c. **Weight**—The weight of the glass reinforced plastic pipe is about ¼ to ⅕ that of steel, and about ⅔ that of aluminum. This light weight facilitates handling, decreases shipping costs and results in a faster installation. These advantages become markedly apparent in

* Buton, Trademark of Enjay Chemical Co.

(Continued on Page 36)



Tank of exhaust gas washer, made by Iowa Manufacturing Co., for use in air pollution control. Neoprene-based coating, used to protect tank from abrasion and corrosive acids, is applied to all interior metal surfaces.

In high-velocity exhaust gas washer...

NEOPRENE COATING GIVES LASTING PROTECTION AGAINST ABRASION AND HOT SULFURIC ACID

Officials of the Iowa Manufacturing Company estimate that this exhaust gas washer tank will serve indefinitely, given proper maintenance. Previously, life span for their unprotected tanks was less than a year. What has made the difference? A protective coating of abrasion and acid-resistant Du Pont neoprene.

The company experienced severe corrosion problems on units installed in asphaltic concrete plants before finding this solution. Their washers, used for the control of air pollution, employ high-pressure water sprays to remove dust and sulfur dioxide before the exhaust gases are discharged. Inside the tank, water sprays cool the hot (300°F.) sulfur dioxide and trioxide gases and form sulfuric acid. A 5 mil neoprene coating protects the steel tank from this corrosive acid and high-velocity dust-bearing gas.

Neoprene's unique combination of properties includes proven, dependable resistance to abrasion and acids as well as to flame, oil, grease, weather, sunlight, heat, chemicals and ozone.

For information to help solve your corrosion problems, write for a copy of PROTECTIVE COATINGS AND LININGS. E. I. du Pont de Nemours & Co. (Inc.), Elastomer Chemicals Department C-11, Wilmington 98, Delaware.

DU PONT REG. U. S. PAT. OFF.

NEOPRENE
SYNTHETIC RUBBER

Better Things for Better Living... *through Chemistry*

Plastic Pipe—

(Continued From Page 34)

larger sizes. For instance, 6 or 8-inch plastic pipe can be handled readily by one or two men, whereas power equipment is needed to handle steel pipe of the same diameter.

During a recent installation, a time comparison was made between ditching 2-inch steel pipe and plastic pipe. While five men required two hours to ditch 500 feet of the steel pipe, three men took only 45 minutes to ditch the plastic pipe and with considerably less effort. In both cases, trench excavation and backfilling were, of course, the same and are not included in the time comparison.

d. **Flow Characteristics**—The interior surface of glass reinforced plastic pipe generally is smoother than steel, perhaps approaching that of glass. The Williams & Hazen flow coefficient is in the range of 145-150, whereas steel is about 130. This will yield greater flow through plastic than through steel pipe under the same conditions. Furthermore, the coefficient tends to decrease with time for steel (to about 90) as corrosion occurs, whereas with plastic, it remains relatively constant.

In recent tests at Massachusetts Institute of Technology, a 2-inch diameter glass reinforced plastic pipe has shown at least a 10 percent greater water flow than through an equivalent steel pipe under the same pressure.[6] Comparing flow through a steel pipe with that through PVC (the friction factors are comparable to reinforced plastic and much more comparative data are available), it can be shown that for 300 gpm, the head loss is only 4 ft./100 ft. as compared to about 9 ft/100 ft. for steel in a 4-inch diameter pipe. The head loss is proportionally lower for plastic with other flows and other pipe sizes (in the small diameter range).

e. **Anti-Fouling Characteristics**—In handling highly paraffinic crudes, wax deposition along metallic pipe walls can be a serious problem. In some oil fields, even though oversized pipe is used, the lines must be cleaned as often as every other day.

In plastic pipe the rate of paraffin deposition is radically reduced. In most cases, there is no deposit. This is probably due to the smoothness of the pipe, its low thermal conductivity, and its noncompatibility with the wax. Recent tests at the University of Texas have not only demonstrated reinforced plastic pipe's superiority in this respect over metallic pipe, but also indicate some advantage over thermoplastic pipe.[7]

f. **Heat Transfer**—The low heat transfer characteristics of plastic are well known. The military is using plastics where skin temperatures are in the thousands of degrees while the interior is relatively cool.[8] Where heated liquids are being transported, the advantage of having a low thermal coefficient in the pipe material is readily apparent.

g. **Pipe Strength**—Static bursts on 2-inch diameter pipe have shown ultimates of up to 8000 psi internal pressure or 70 to 80,000 psi tensile strength. These values compare quite favorably with steel pipe. As a matter of fact, if a steel pipe were tested in series with the same dimensioned (same ID and OD) glass reinforced plastic pipe, the steel pipe might very well fail before the plastic.

However, this is not the complete story. If the 8000 psi pipe were held at some lower pressure, say 4000 psi, failure might occur in a very short period of time. The long term strength of the pipe is quite dependent upon the time, pressure, temperature and environment. The only reliable method presently available to predict safe operating pressures is to test under long term conditions. It is doubtful that any universal correlation for determining long term properties from short term tests will be available in the near future; much still must be learned of the mechanisms involved.

Test Methods

Because there are no standard tests available for glass reinforced plastic pipe, appropriate test methods have had to be established. The tests described here are primarily aimed at measuring the bond strength between plastic and glass in terms of pipe performance. This is deemed a most important variable. Static bursts show bond strengths to be quite good initially, for the full strength of the glass is usually reached. However, if the bond is lost or glass destroyed, with time, additional stress will be transferred to the working glass until the ultimate is reached and failure occurs.

The two factors tested for their effect on bond are pulsations in the pipe and long term water attack on the bond.

Pulsating Pressure

The pulsating pressure test is designed to give a yes or no type of answer, because conditions are far more severe than the pipe ever would meet in the field. However, quantitative data also can be obtained.

Two-inch diameter pipe, two feet long, is capped with one end valved to receive hydraulic pressure. The pipe ends are free to move; the pipe receives a triaxial stress. Pressure is applied to the pipe in cycles of from 0 to 1000 psi at a rate of 1 cycle per second; the pressure varies sinusoidally. If the pipe passes 2×10^6 cycles at 150 F it is deemed to have passed. However, in general, in subsequent burst tests 50 percent strength retention is found.

Sustained Pressure (Stress-Rupture Test)

The sustained pressure test yields perhaps the most valid type of information because it most nearly approximates field conditions. Unfortunately, tests must be run for several years before meaningful data is obtained.

In this test, as run at Esso Research and Engineering Company, the pipes are submerged in a 150 F water bath, hydrostatic pressure is applied and maintained. The time to failure is recorded. The temperature selection is arbitrary and serves to limit the scope of the test. For a more complete performance picture, the entire temperature range should be covered. Pressure selection is also arbitrary; 75, 50 and 25 percent of the ultimate pressure is recommended as giving significant data. Since various strength pipe is being tested here, pressures of 2500, 1500, 1000 and 500 psi currently are being used.

Fresh water is used because this readily attacks the glass fiber bond. Distilled water is probably one of the most corrosive fluids the pipe could carry. The water will not only attack the bond but will actually dissolve glass. Because the surface area of the fiber is so great compared to its volume, the fiber is readily destroyed. On the other hand, salt water has less effect.[9]

Figure 2 shows a top view of a small segment of the laboratory test apparatus. The left portion of the picture shows the pulsating pressure test; the sustained pressure test is on the right. The three pumps around the edge of the pit hold the constant pressure in the pipe below. A fourth pump was added subsequently to provide a means of testing five-foot lengths in addition to increasing the test facilities by 200 percent.

Results are readily translated into stress-rupture curves. One particular pipe which had a static burst of about 4000 psi was found to fail at approximately the following values: 2500 psi—1 day; 1500 psi—1 month; 1000 psi—1 year; 500 psi —>29 months.

When plotted on the appropriate coordinates (log-log appears most suitable), the values produce a straight line. Upon selecting the desired life of the pipe, the operating stress is indicated from this curve. Applying a moderate factor of safety will give a practical operating pressure, under the test conditions. If the test conditions are similar enough, this pressure may be recommended as a field operating pressure. If not, further adjustments in the factor of safety, dependent upon expected operating conditions are necessary. Assuming the service conditions are less severe than this test (i.e., not continuously submerged in fresh water at 150 F), this curve can be expected to shift upwards. Because the curve is plotted on logarithmic coordinates, it takes very small shift in the curve to substantially increase the practical life. Conversely, a relatively small increase in the severity of the service conditions can markedly reduce the servicable life. Consequently, extreme care should be exercised when applying these curves.

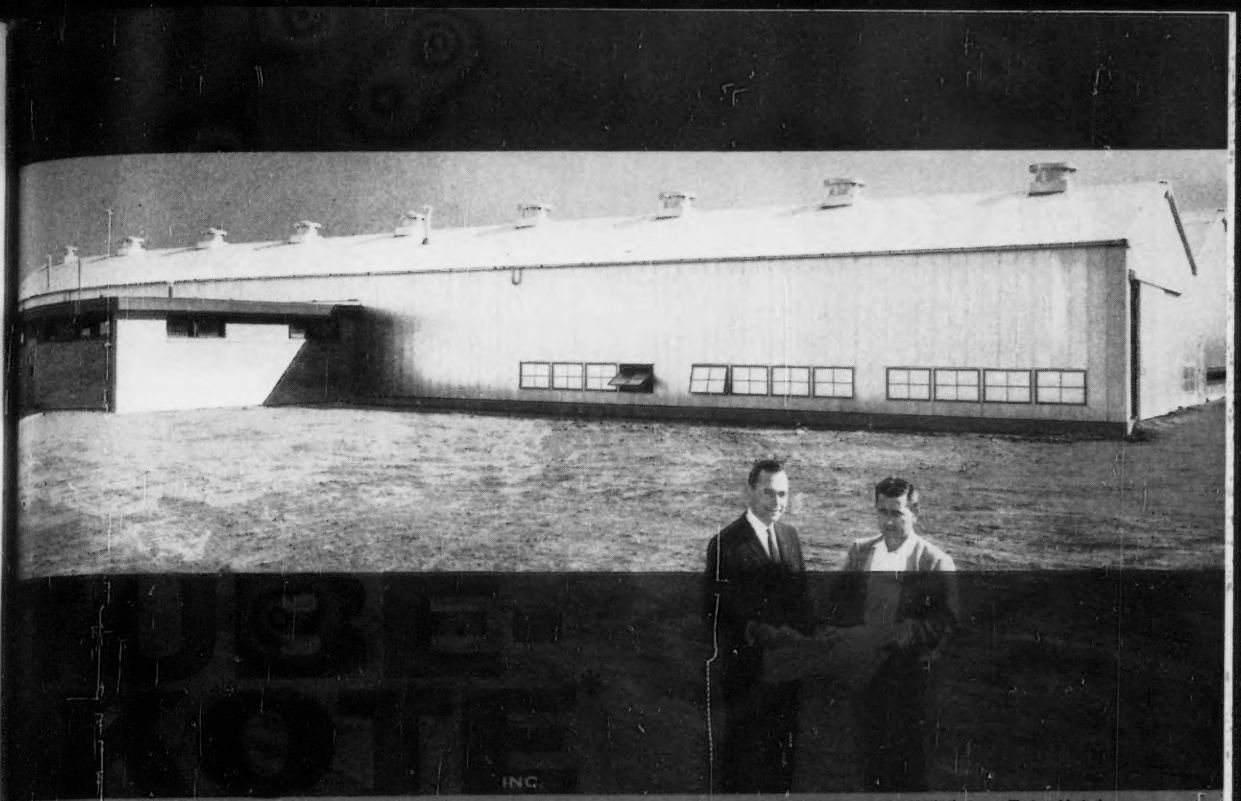
Figure 3 shows a typical stress-rupture curve obtained. Each point represents one or more test values. As can be seen, although the pipe will originally fail at a hoop tensile stress of 65,000 psi under the conditions tested, a 5:1 factor of safety is inadequate. A factor of safety in the range of 10:1 to 20:1 is called for (depending on field conditions and length of service required).

(Contined on Page 38)

TABLE 2—Demonstrated Uses of Glass Reinforced Plastic Pipe[10]
(Partial Listing)

Fluid Transported	Temperature F	Pressure psi
Hydrochloric acid, conc'd.	60–260	0–500
Hydrofluoric acid, 10–30 percent	100–300	0–85
Phosphoric acid, 40–79 percent	200–300	50–200
Sulfuric acid, 60 percent	260	30–300
Sulfuric acid, 10–50 percent	100–290	0–250
Nitric acid, 5 percent	180	100
Chlorine, dry	90–120	35–75
Brine	40–275	0–1350
Benzene	80–120	150–500
Xylene	60–200	15–700

*T.M. Reg.



Left to right: Joe H. Williams, Tube-Kote's Canadian Plant Manager and Mack E. Dominy, Plant Supervisor are shown in front of the new Tube-Kote Plant in Edmonton, Alberta, Canada.

ANNOUNCES NEW CANADIAN PIPE COATING PLANT

Tube-Kote, Inc.'s new plant is designed to help solve paraffin and corrosion problems of Canadian oil and gas production. It occupies an 8½ acre plot in the Cornet addition of Southeast Edmonton. The plant is the newest, most modern, fully automated facility to be found for coating oil field tubular goods with baked-on plastic coatings.

CASE HISTORIES ON REQUEST

Let a Tube-Kote representative show you actual case histories proving the economy of applying the Tube-Kote coatings to your oil field tubular needs. Tube-Kote can save you money when you are faced with paraffin control and corrosion problems.

TUBE-KOTE INC.

FIRST NAME IN CORROSION RESISTANCE

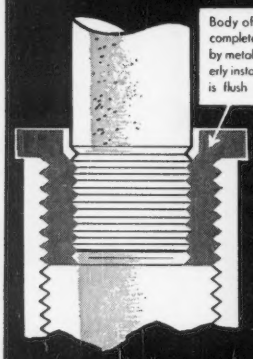
P. O. Box 20037 Houston 25, Texas

Branch Plants: Harvey, Louisiana; Midland, Texas; Edmonton, Alberta, Canada

*T.M. Reg. U.S. Pat. Off.

MAYCO

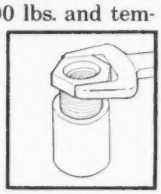
NYLON DIELECTRIC BUSHINGS



Stop Electrolysis!

■ Sandwiched between two dissimilar metals, Mayco nylon dielectric bushings prevent metal to metal contact – stop *electrolytic* action!

Able to withstand pressures in excess of 1000 lbs. and temperatures over 300°F, Mayco dielectric bushings gain added strength from clamping action of surrounding metal.



Most sizes also available with extra-heavy "Hex" to facilitate use of ordinary wrench.

Couplings and unions also available factory equipped with Mayco bushings.

Order Mayco Dielectric Bushings from your jobber or write to:

MAY PRODUCTS, INC.

BOX 427, GALESBURG, ILLINOIS

Manufacturers of: MAYCO dielectric fittings and MAYCO water softeners and filters

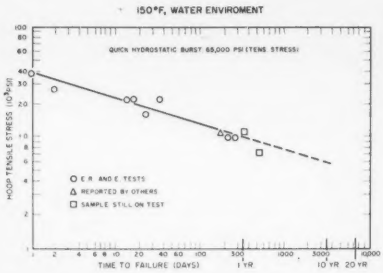


Figure 3—Typical S-N curve, glass reinforced plastic pipe.

Figure 4—Testing glass reinforced plastic pipe for fire resistance.

Plastic Pipe –

(Continued From Page 36)

Because most manufacturers are relatively new in the field, curves of this nature are not presently available. It is believed, however, that as the various manufacturers progress with their laboratory tests, these curves will be common.

Other Tests

To obtain specific data other tests should be run. Significant information was obtained from tests such as flexural, compression and crushing. Heat distortion, vibration, weathering and chemical resistance tests have given indications of field performance. In the case of well tubing applications, pull tests and collapse pressure tests are significant.

One of the major considerations in refinery applications is fire resistance. Consequently, the pipes were subjected to a gasoline fire for 15 minutes (see Fig. 4). Results of this test showed that all the pipe could maintain fluid at 30 psi without any leakage due to fire damage and that they were much superior to thermoplastics and comparable to aluminum. This is probably because the tightly wound glass cage serves as a fire retardant. While being by no means a fire resistant material, the pipe bears consideration in non-critical refinery areas.

Applications

In the petroleum industry, the principal use of glass reinforced plastic pipe is believed to be in crude gathering lines, salt water disposal lines and water flooding operations. As down hole tubing, it has been used in salt water disposal wells, pumping wells and combination injection and disposal wells.

The chemical industry is obviously finding considerable use for it in handling varied reagents, acids and alkalies.

Applications also can be found aboard tankers, in food processing, industrial waste disposal and in the paper industry.

In any installation, economics of various materials are always an important factor. In general, the cost of 2-inch diameter reinforced plastic pipe is about twice that of PVC, 3½ times that of carbon steel and about ¼ to ½ that of stainless. In large sizes, the cost picture changes somewhat, making the potential plastic cost almost the same as that of carbon steel. If any further protection, such as coatings or linings, is required on steel pipe, the balance falls in the other direction and the glass reinforced plastic pipe often is more economical. It should be noted also that steel prices are continually rising, whereas plastic prices are declining. Furthermore, reductions in reinforced plastic pipe prices are anticipated as the manufacturers increase their volumes and as processes are refined.

Generally, there is a lack of variety of fittings. The only universally available fitting is the straight coupling. Furthermore, there is lack of standardization of couplings (in addition to pipe). Presently employed coupling systems use an AST thread, and API thread, adhesive and "O" ring joint and flanges.

At present, Standard Oil Company (N. J.) affiliates have in operation in test installations over 18,000 feet of pipe. Most of this is in salt water disposal systems and water flooding operations. There is, however, one test installation of 1900 feet down-hole in a salt water injection well. Prospects for further applications appear good.

Conclusion

Glass reinforced plastic pipe has properties markedly different from those of the thermoplastics. Much higher operating pressures and temperatures are possible. Some manufacturers recommend up to 1500 psi at 200 F. Glass, which makes up 60 to 80 percent of the pipe, has very high tensile strengths—over 100,000 psi. The plastic imparts corrosion resistance and thus eliminates the need for coatings, wraps, lining, cathodic protection and inhibitor injection. Furthermore, the plastic is non-contaminating for most uses.

Other incentives for use of the pipe are its light weight, which speeds installation; better flow characteristics with little or no paraffin deposition and its low heat transfer. High strengths exhibited, however, can be deceiving. Long term tests give a more realistic picture of pipe performance. A sustained pressure test currently being run is in which the samples are held at various pressures in a 150 F water bath. If the log of time to failure is plotted against the log of pressure or stress, a straight line is obtained. By adjusting this curve by a factor which reflects the pipe's service and the factor of safety desired, a safe operating pressure may be recommended for any desired life.

References

1. C. Crespi. *Materials in Des Eng*, **47**, 110 (1958) Jan.
2. P. Morgan. Glass Reinforced Plastics. Philosophical Library Inc., New York, 1954, pp. 117-140.
3. R. H. Sonneborn. Fiberglas Reinforced Plastics, Reinhold Publishing Corp., New York, 1954, pp. 15-20.
4. H. Clark and B. M. Vanderbilt. S.P.I. 14th Annual Tech. and Management Conf., Sect. 17-C (1959).
5. G. Sorell, *Chem Eng*, **66**, 154 (1959) March.
6. E. R. Gilliland. Private communication.
7. F. W. Jessen and J. N. Howell. *AIME Trans*, **213**, 81 (1958).
8. *Modern Plastics*, **35**, 105 (1958) June.
9. W. H. Sharp and M. K. Weber. *Corrosion*, **12**, 71t (1956) Feb.
10. H. D. Boggs and E. D. Edmisten. *Corrosion* **14**, 114 (1958) May.

...THE ANSWER TO YOUR CORROSION PROBLEMS?

ATLAC® 382

... the DIFFERENT polyester

Lightweight, sturdy, reinforced plastic equipment—made with ATLAC 382 bis-phenol polyester resin—may offer an efficient, economical solution to your equipment corrosion problems. This unusual resin has maintenance applications, too: in glass reinforced tank linings and in "putty" materials for repairing cracks and holes in steel ducts and concrete floors.

ATLAC 382 is a special bis-phenol polyester which almost universally retains a higher percent of original strength under corrosive conditions than general purpose polyester and isophthalic resins. See for yourself—write for our new comparative study* on the effects of corrosive chemicals on various resins.

Scrubber withstands hot nitric fumes

A scrubber made of glass-reinforced ATLAC 382, designed and fabricated by CORITE-REYNOLDS CORP. of Des Plaines, Ill., prevents the escape of destructive nitric acid fumes in the thorium production plant of the LINDSAY Chemical Div. of American Potash & Chemical Corp. During its 6 years of constant exposure to hot acid fumes and droplets and a dilute caustic solution used for wash-down, the scrubber has never needed repair or maintenance. It cost about one-third as much as a comparable stainless steel scrubber—a sizeable saving on initial investment as well as on maintenance costs.

CHEMICALS DIVISION
ATLAS POWDER COMPANY
WILMINGTON 99, DELAWARE

*Presented before the Society of the Plastics Industry, Feb., 1960.

In Canada: Atlas Powder Company, Canada, Ltd., Brantford, Ontario, Canada

NEW address equipment LOWER prices

MILD STEEL

Rectangular Specimens as low as

75c each

IN LOTS OF 50

Consult Us for Your Testing Needs

Over 60 Materials in stock for QUICK DELIVERY

CORROSION Test Supplies Co.

P.O. Box 176, Baker, La.
Phone BATON ROUGE — WE 3-1315

WE SHIP ANYWHERE IN THE WORLD

Second Table

Generic Terms, Manufacturers Listed for 38 More Plastics

Generic and trade names for 38 plastic materials are listed below with the name of the manufacturer as a supplement to the list published on Page 40 of the June issue of CORROSION.

Trade names listed below with an asterisk are corrections for the table published in the June issue.

Corrections and additions to this table for publication at a later date should be submitted to Dale Miller, Corrosion Magazine, 1061 M & M Bldg., Houston 2, Texas.

PLASTICS TABLE

Trade Name	Generic Name	Manufacturer
Amer-Plate	Polyvinyl chloride sheet	Amercoat Corp.
Araldite	Epoxy resins	Ciba
Atlac 382*	Polyester	Atlas Powder
Baker PL-12	Acrylic thermoplastic polymer	J.T. Baker Chemical
Beslon	Acrylic fiber	Toho Rayon (Japan)
Bonate	Polyester	Beetle Plastics
Chemiseal	Polytetrafluoroethylene	U.S. Gasket
Chem-Weld	Styrene-rubber alloy pipe	Southwestern Plastic Pipe
Cycolac	Acrylonitrile butadiene styrene polymer	Marbon Chemical
Duracor	Reinforced thermosetting resin	Ceilcote
Duracron	Thermosetting resin	Pittsburgh Plate Glass
Duracryl	Thermoplastic resin	Pittsburgh Plate Glass
Duralon	Furfural resin	U.S. Stoneware
Dylan	Polyethylene	Koppers
Dylex	Styrene-butadiene	Koppers
Ethocel	Ethyl cellulose	Dow Chemical
Fluorel	Fluorocarbon elastomer	Minnesota Mining
GEC-111	Glass epoxy laminate sheet	Taylor Fiber
Geon*	Polyvinyl chloride resin	B.F. Goodrich
Hetron	Chlorinated polyester resin	Hooker Chemical
Koroseal*	Rigid polyvinyl chloride pipe and sheet	B.F. Goodrich
Kotol	Ethyl cellulose	U.S. Rubber
Kralastic*	Acrylonitrile butadiene styrene	U.S. Rubber
Kraloy	Rigid polyvinyl chloride pipe	Kraloy Plastic Pipe
Marlex 50	Linear polyethylene	Phillips Chemical
Perbunan	Butadiene acrylonitrile rubber	Enjay
Plastaloy	Unsaturated polyester	Atlas Mining Products
Poly-Eth	Polyethylene	Spencer Chemical
Polypenco T	Polytetrafluoroethylene	Polymer Corp.
Pro-Fax	Polypropylene	Hercules Powder
Rigidon	Unplasticized polyvinyl chloride, glass reinforced	Heil Process
Rigivin	Unplasticized polyvinyl chloride	Heil Process
Telec-Con	Acrylonitrile butadiene styrene communications conduit	Southwestern Plastic Pipe
Tenite I*	Cellulose acetate	Eastman Chemical
Tenite II	Cellulose acetate butyrate	Eastman Chemical
Teviron	Polyvinyl chloride fiber	Teikoku Rayon (Japan)
Uniparr	Pre-stressed fiber glass sheet	X-Port Oils, Inc.
Vitel	Polyester resin	Goodyear Tire

Now on an installed-cost basis—

FLUOROFLEX-TS

TEFLON-LINED STEEL PIPE COMPETITIVE IN COST WITH COMPARABLE HIGH-CORROSION-RESISTANT PIPING MATERIALS!

®Fluoroflex is a Resistoflex trademark, reg. U. S. Pat. Off. ®Teflon is DuPont's trademark for TFE fluorocarbon resins.

Recent price reductions are the reason. They have been made possible, in many of the popular pipe sizes, by advanced technology, production improvements, and ever-increasing sales volume.

It is now possible to pipe your entire process in corrosion-impervious Fluoroflex®-T, at prices comparable, on an installed basis, with conventional piping material of far less corrosion resistance, particularly at elevated temperatures.

Case histories of economies resulting from Fluoroflex-T are being increasingly reported, citing ease and speed of installation with prefabricated lengths, lower checkout time, decreased maintenance, long equipment life, and elimination of process headaches and downtime. One plant equipped with Fluoroflex-T, in fact, reported savings of $60,000 per month in costs of maintenance, downtime, and product loss.

Why not investigate what a Fluoroflex-TS piping installation can mean to your company, in installed costs, overall economy, and long process life? Write for complete information today!

Complete corrosion protection: Fluoroflex-T, the proprietary Teflon® product manufactured and fabricated solely by Resistoflex, is completely resistant to any chemical (except high-temperature fluorine and the molten alkali metals) up to 500° F.! It combines optimum strength and non-porosity.

Check these features:

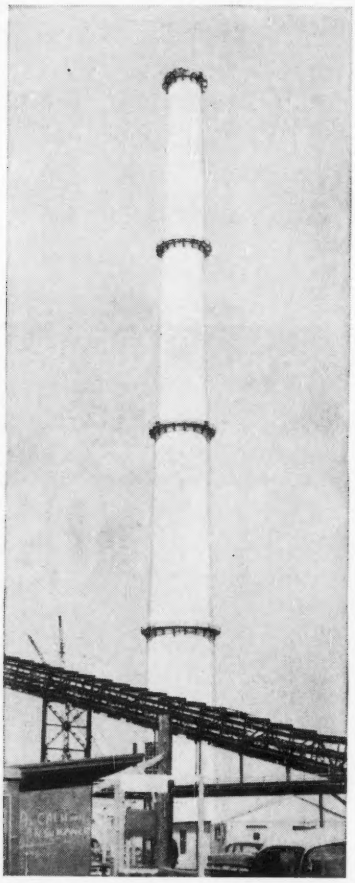
- Liner in thermal equilibrium with housing, stays in place despite wide temperature variations, eliminating fatigue collapse and flare cracking.
- Lengths prefabricated to size, ready to install.
- Fittings compatible with all standard piping systems.
- Complete family of piping components available.
- Gasket and sealing problems eliminated by integral gasket formed from liner over full face of flange.

RESISTOFLEX
CORPORATION

Complete systems for corrosive service

Plants in Roseland, N.J. • Anaheim, Calif. • Dallas, Tex.
Sales Offices in major cities

See how



FOAMSIL®

PROBLEM: REFRACTORINESS

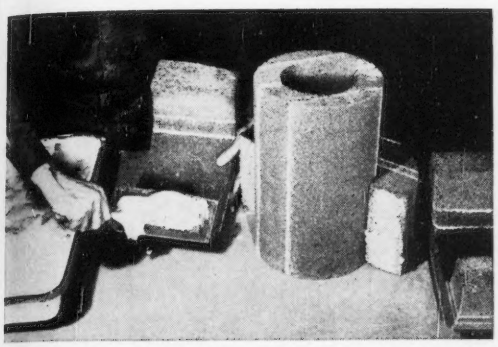
At Consolidated Edison's Arthur Kill Station, FOAMSIL protects concrete stacks from hot gases and fast deterioration. The life expectancy of the 500-ft. stacks is increased because the 99 per cent pure fused silica insulation stays impervious to acids and takes *continuous* operation up to 2000°F. (FOAMSIL withstands cyclic temperatures ranging from —450°F to +1600°F.) Joints are sealed with Pennsalt Chemical's Synar silica cement to insure uniform insulation value.

PROBLEM: THERMAL SHOCK

The unique refractory properties of FOAMSIL eliminate the problem of insulation cracking due to thermal shock. This solved a problem for Silverstein's Bakery, Toronto, where chimney walls were overheating. Though the incinerator was not used continually, it was called on to withstand flash temperatures as high as 1000°F and lower temperatures higher up the stack. The old insulation was ripped out and FOAMSIL was installed in *one* working day. FOAMSIL has a coefficient of expansion of only .00000035. The stack has gained more cross-section area since only 2½ inches of FOAMSIL were required.

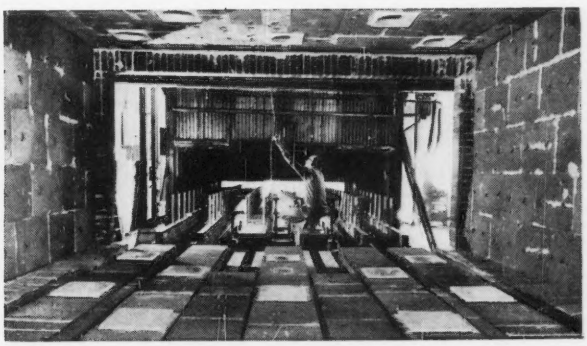
PITTSBURGH PC CO

solved major refractory and insulation problems for these users



PROBLEM: ACID EXPOSURE

FOAMSIL is completely resistant to all acids except hydroflouric and hot phosphoric. This protection against acids and acid vapors, fumes and liquids of all kinds led Union Carbide Chemicals Company to apply it in piping, stack, and vessel applications for sulphuric acid at their plant in South Charleston, W. Va. FOAMSIL cannot become saturated with vapors or liquids. Carbide uses FOAMSIL insulation as a tank lining where the sulphuric acid content is as high as 95 per cent, and the temperatures sometimes soar to 480°F. Two mortars that are compatible with the qualities of FOAMSIL are Pennsalt Synar silica cement No. 68 and FOAMSIL No. 1120.



PROBLEM: LOW HEAT CAPACITY

Pacific Scientific, Bell Gardens, Calif., used FOAMSIL to line a portable brazing furnace because of its lightweight, extra-support strength and resistance to heat. A saving of 80 per cent or $80,000 over normal heating equipment was achieved because the use of FOAMSIL meant only a fraction of the usual firing equipment was needed. FOAMSIL's low residual heat capacity and low heat storage capacity make it possible to heat materials to the necessary high temperature rapidly and remove heat quickly to allow the braze to set. Five inches of FOAMSIL does the work, leaving more working area in the 91 ft. x 1 ft. furnace which handles honeycomb aircraft and missile sections measuring 12 ft. x 20 ft. and 4 ft. high.

Use the coupon to get a testing sample:
Test FOAMSIL for your most troublesome refractory or insulation application . . . from tank lining to insulation of furnace, oven or stack. FOAMSIL is available in block sizes 17″ x 22″ in a variety of thicknesses. Send for a free sample and literature to: Pittsburgh Corning Corporation, Department CO-110, One Gateway Center, Pittsburgh 22, Pa. In Canada: 3333 Cavendish Blvd., Montreal, Que.

CORNING

Name_____

Company_____ Title_____

Address_____

City_____ Zone____ State_____

TABLE 1—Six Months' Test of Polyester Plastic Castings—210°F

Bisphenol-Based Polyester

Corrodent	Flexural Strength, psi	Percent Retention	Modulus Elas., x 10^6	Percent Retention	Barcol Hardness
None	18,100	—100	0.46	—100	30–35
5% Nitric Acid	3,820	20	0.46	100	38–40
25% Sulfuric Acid*	11,200	62	0.47	102	35–41
15% Hydrochloric Acid	11,490	63	0.47	100	37–39
25% Acetic Acid	8,540	47	0.41	89	34–36
5% Alkaline Detergent	9,390	53	0.45	98	36–38
5% Sodium Hydroxide	10,790	65	0.43	93	39–40
Water	14,350	79	0.44	96	37–39
Bleach 5.25% Sodium Hypochlorite	10,730	59	0.45	98	37–39

General Purpose Polyester

None	18,172	—100	0.62	—100	45–55
Nitric Acid	Complete Deterioration 1–3 Mo.				
Sulfuric Acid	Complete Deterioration 1–3 Mo.				
Hydrochloric Acid	Complete Deterioration 3–6 Mo.				
Acetic Acid	Complete Deterioration 3–6 Mo.				
Alkaline Detergent	Deteriorated 1–3 Mo.				
Sodium Hydroxide	Sample Dissolved Less Than One Week				
Water	1,720	9	0.23	37	20–22
Bleach	Complete Deterioration 3–6 Mo.				

Isophthalic

None	16,241	—100	0.57	—100	40–55
Nitric Acid	1,000	6	0.19	33	2– 4
Sulfuric Acid	5,940	37	0.33	57	25–36
Hydrochloric Acid	930	6	0.30	52	5– 6
Acetic Acid	1,420	9	0.14	24	4– 8
Alkaline Detergent	Deteriorated 1–3 Mo.				
Sodium Hydroxide	Complete Deterioration Less Than One Month				
Water	2,150	13	0.21	36	7– 9
Bleach	1,860	11	0.18	31	8–11

* Three months only—Sample lost previous to 6-month tests.

TABLE 2—Room Temperature Cure Laminates 50/50 Resin Glass "C" Glass Veil Overlay 3 Months @ 210 F

Bisphenol-Based Polyester

Corrodent	Flexural Strength, psi	Percent Retention	Modulus Elas., x 10^6	Percent Retention	Barcol Hardness
None	39,000	.....	1.37	.....	55–65
Nitric Acid	22,160	57	0.98	71.5	45–50
Sulfuric Acid	17,610	45	0.94	68.5	32–40
Hydrochloric Acid	12,930	33	0.75	55.0	30–38
Acetic Acid	24,000	61	0.93	68.0	42–50
Alkaline Detergent	27,250	70	1.36	100	40–50
Sodium Hydroxide	11,080	28	0.88	64.0	30–37
Water	27,350	70	1.25	91.0	50–54
Bleach	26,200	67	0.61	44.0	54–60

General Purpose Polyester

None	28,900	.....	0.93	.....	50–60
Nitric Acid	4,580	16	0.66	71.0	4– 8
Sulfuric Acid	2,900	10	0.39	42.0	10–15
Hydrochloric Acid	10,570	37	0.60	64.0	32–40
Acetic Acid	8,990	31	0.61	65.0	15–18
Alkaline Detergent	6,380	22	0.38	41.0	.....
Sodium Hydroxide	Sample Dissolved Less Than One Week				0
Water	14,240	49	1.01	109	38–42
Bleach	16,400	55	1.8	120	42–50

Isophthalic Polyester

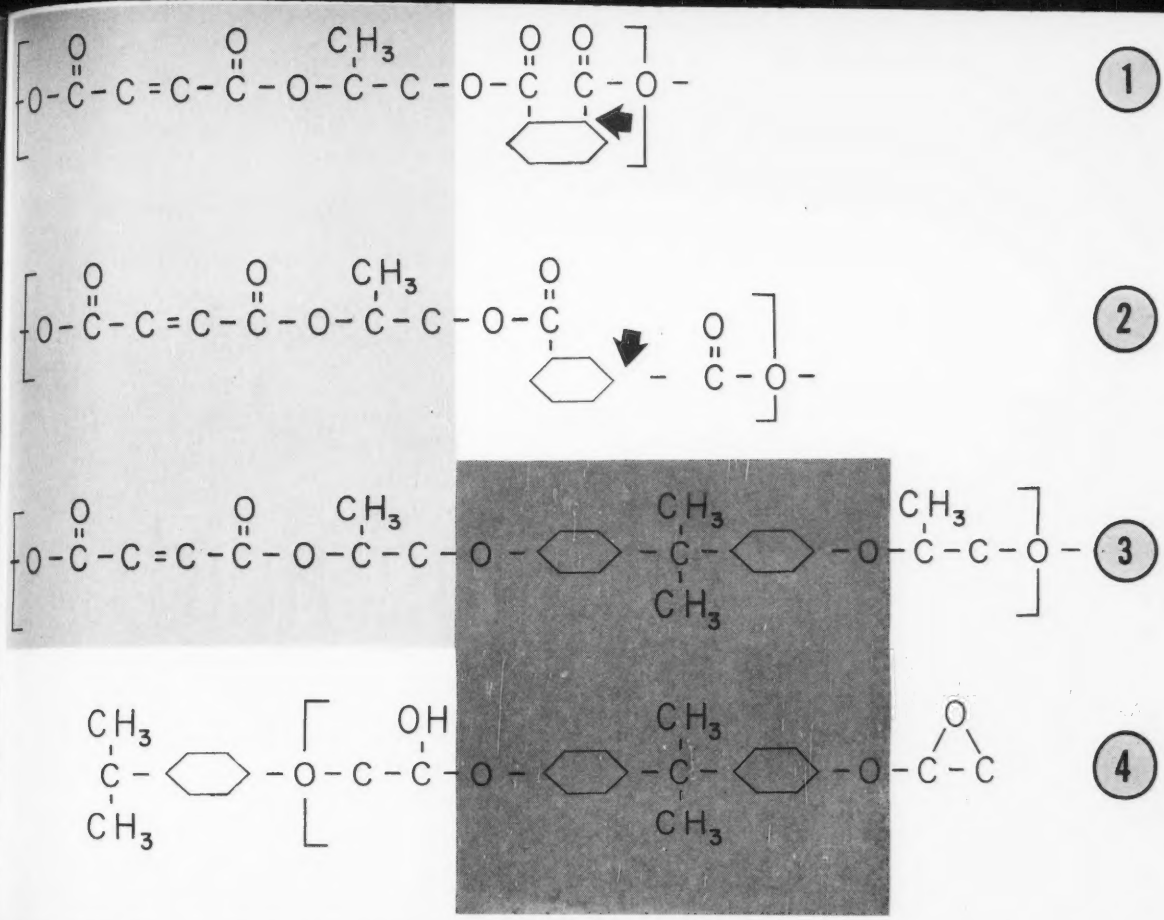
None	43,560	.....	1.47	.....	59–65
Nitric Acid	16,120	37	0.86	58.0	40–44
Sulfuric Acid	13,250	30	0.78	53.0	43–50
Hydrochloric Acid	13,320	31	0.72	49.0	40–43
Acetic Acid	12,300	28	0.74	50.0	32–34
Alkaline Detergent	3,760	8.7	0.33	21.0	.....
Sodium Hydroxide	Complete Deterioration Less Than One Month				0
Water	21,333	49	1.14	78.0	46 50
Bleach	18,800	41	0.89	60.0	46–52

Some

High
Poly

INITIA
polye
phthalic
tions hav
The tes
and und
the bisp
flexural
(rigidity
material
Tabu
teristics
after t
various

★Revise
of the
Polyes
and a
April



ORGANIC FORMULAS shown above are (1) general purpose polyester, (2) isophthalic polyester, (3) Atlac 382, a patented bisphenol based polyester and (4) epoxy resin. Molecular structure common to Formulas 1, 2 and 3 is shown by the colored area on the left. The only structural difference between 1 and 2 is the placement of the CO_2 radical indicated by the colored arrows. The bisphenol group common to Formulas 3 and 4 is shown by the colored area on the right.

Some Results From

*High Temperature Testing of Polyester Castings and Laminates**

S. S. Feuer and A. F. Torres

Atlas Powder Company
Wilmington, Delaware

Abstract

Results of six months' tests of castings of three polyesters and three months' testing of laminates of the same materials in eight corrodents at 210 F are given. Corrodents were 5 percent nitric, 25 percent sulfuric, 25 percent acetic and 15 percent hydrochloric acids; 5 percent sodium hydroxide, an alkaline detergent, a bleach (5.25 sodium hypochlorite) and distilled water.

Under conditions of the tests, a bisphenol-based polyester has significantly better resistance than a general purpose polyester or an isophthalic polyester. Test data are given in percentage retention of flexural strength, modulus of elasticity and hardness. 3,2

INITIAL TESTS of a bisphenol-based polyester, a general purpose and an isophthalic polyester in eight corrosive solutions have given useful but not final results. The tests indicate that, in the corrosives and under the conditions of the tests made, the bisphenol-based material retains more flexural strength and modulus of elasticity (rigidity) than either of the other two materials.

Tabular data at the left shows characteristics of polyester plastic coatings after three and six-month exposures to various corrosives.

There is some indication that one-year tests will give information reliable for engineering use and lead to reliable shorter range tests.

The advantage of a resin-rich layer exposed to the corrodents is evident.

The tests revealed the following facts, among others: (1) Nitric acid is the most aggressive of the corrodents tested. (2) Isophthalic and bisphenol-based polyesters are approximately equal in resistance to bleach. (3) Bisphenol polyester exhibited unusual caustic resistance, retaining 60 percent of original flexural strength after six months. The other two materials disintegrated in less than one month. (4) Fast screening tests are not valid for computing long-term serviceability.

★Revision of a paper titled "Comparative Study of the Corrosion Resistance of a Bisphenol Polyester Resin, A General Purpose Polyester and an Isopthalic Polyester Resin," submitted April 6, 1960, for publication.

Bibliography

C. A. Burt. An Investigation of Non-Metallic Pipe for Use with Liquid Corrosives. *Corrosion*, **16**, 25 (1960) February.

S. W. Shepard. Use of Plastics as Materials of Construction. *Corrosion*, **10**, 215 (1954) July.

Oil Field Structural Plastics Test Data Are Given. *Corrosion*, **10**, 17 (1954) July.

Service Reports Given on Oil Field Plastic Pipe. *Corrosion*, **10**, 9 (1954) September.

Results of Survey on Plastic Materials Use by NACE Committee T-5D. *Corrosion*, **10**, 9 (1954) November.

Reports to Technical Unit Committee T-1J on Oil Field Structural Plastics. *Corrosion*, **11**, 57-60 (1955) November.

W. H. Sharp and M. K. Weber. Effect of Water on Strength of Structural Plastics. *Corrosion*, **12**, 71t (1956) February.

AMCHEM Information Bulletin

Facts about pickling acid inhibitors

Nearly 40 years ago Amchem developed the first pickling acid inhibitor—RODINE—and with it revolutionized acid pickling. Only a few of the steel mills of the time believed that the addition of less than one percent RODINE to a sulfuric acid pickling bath could save substantial amounts of acid and metal, while increasing the life of the bath. Today there is no mill chemist who does not know about RODINE and its proven performance in eliminating waste of valuable metal and acid, and its ability to pay for itself through the savings thus gained.

In the past few years much attention has been focused on the use of wetting agents to accelerate pickling. But the fact remains that pickling cycles cannot be reduced by the use of wetting agents alone without severe overpickling problems. Wetting agents do help the acid run off surfaces removed from pickle baths, and, in so doing, reduce carry-over of acid into the rinse.

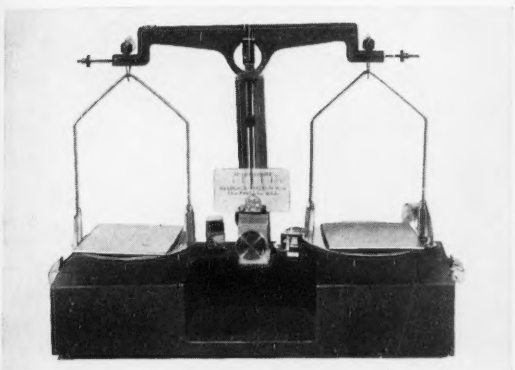
Wetting agents should not be confused with inhibitors to protect the metal and save acid wasted in pitting it. They should not be expected to miraculously speed the removal of scale, even at the expense of wasting the metal. However, the *proper* combination of *real inhibitor* plus correct wetting agent can have beneficial effects on pickling practices.

Only a true inhibitor such as RODINE can offer steel producers solid advantages in pickling. Baths can be operated longer and less acid is required to keep them at desired concentration. Costs of charging and cleaning the bath are reduced, less handling and storing of acid is required. A RODINE bath produces far fewer rejects.—steel emerges with uniformly smooth, bright clean surfaces, free of pits, blisters and smut.

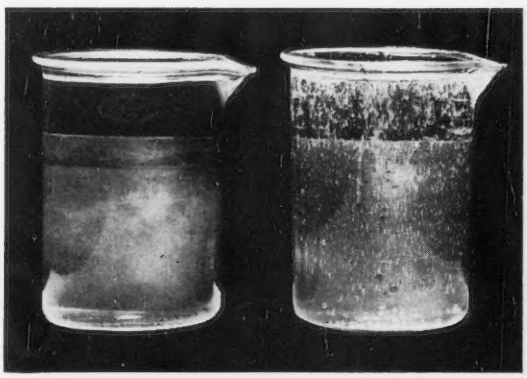
When an Amchem Technical Representative enters your pickle house, you can be assured of experienced assistance in improving your pickling. He will recommend the proper RODINE to 1) prevent needless consumption of acid after scale removal, 2) prevent smutting, pitting and overpickling, 3) produce a stable, free-rinsing foam blanket, 4) improve rinsability and reduce carry-over, and 5) produce a brighter, cleaner surface. Only the Amchem Representative can do this for you because he has at his command the most widely diversified and accepted line of real inhibitors and correct wetting agents available.

Since the early days of pickling acid inhibitor development, scientists in the Amchem Metal Protection Laboratories have constantly studied methods to make the RODINES stronger, more effective and more economical to use. The RODINES of today, as of 40 years ago, are in a class by themselves, have developed a reputation as *the international standard* in acid pickling inhibitors. The fruit of these years of laboratory research and experience in a highly specialized field, and the assistance of Amchem's trained field representatives—specialists in acid pickling techniques—are at your disposal for the asking.

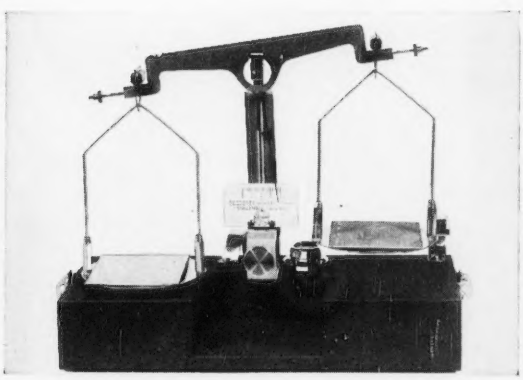
How Rodine Retards Acid's Attack on Metal



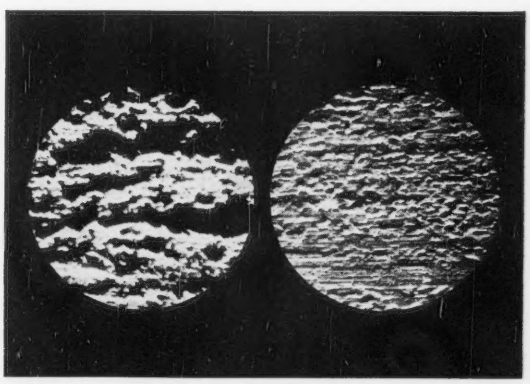
The photographs and microphotographs displayed on this page represent a graphic description of results demonstrating the effectiveness of RODINE in retarding the attack of acid on the metal. NO WEIGHT DIFFERENCE—two identical panels of low-carbon steel are shown being weighed here. They balanced the scale.



RODINE MINIMIZES ACID ATTACK—Each descaled panel was placed in a beaker containing 10% by volume of 66° Bé sulfuric acid of 160° F. The acid in the right-hand beaker was uninhibited. Acid in left-hand beaker was inhibited with RODINE 82, ¼% by volume of the concentrated acid. There was little or no hydrogen evolution in this beaker . . . RODINE retarded the attack of the acid on the base metal.



RODINE SAVES METAL—Both descaled panels were removed from the acid pickle solutions after 5 minutes. The one pickled in the uninhibited acid had lost 1.4% of its original weight. The one pickled in the RODINE-inhibited acid had lost only 0.001% of its original weight. This represents a saving of 26 lb. of steel for each ton pickled; and a simultaneous saving of nearly 50 lbs. of 66° Bé sulfuric acid when RODINE is used to inhibit the acid.



EFFECT OF UNINHIBITED ACID ON THE PANEL — This microphotograph of the low-carbon sheet steel pickled in the uninhibited acid shows deep pits and the crystalline character of the surface after 5 minutes in the solution.

EFFECT OF RODINE-INHIBITED ACID ON THE PANEL — This panel was pickled for 5 minutes in the RODINE-inhibited acid, then microphotographed. Only scale pockets and roll marks are visible; no pitting of the low-carbon sheet steel occurred.

AMCHEM RODINE

Amchem and Rodine are registered trademarks of **AMCHEM PRODUCTS, INC.** (Formerly American Chemical Paint Co.)
AMBLER, PA. • Detroit, Mich. • St. Joseph, Mo. • Niles, Calif. • Windsor, Ont.

One of 180 grounding electrodes installed to depths of 60 ft. under Houston's newest skyscraper, slated to be the tallest structure west of the Mississippi.

only the best for the biggest

Large or small, Cathodic Protection Service provides turnkey installations. Let one of our experienced engineers show you how Cathodic Protection Service can best solve your individual corrosion problems. Call, wire or write the CPS office nearest you.

CPS

cathodic protection service

P. O. Box 66387 Houston 6, Texas JA 6-1981

Cable Address CATPROSERV

CHICAGO 122 S. Michigan Blvd., Rm. 964 WEbster 9-2763

NEW ORLEANS 1627 Felicity JAckson 2-7316

TULSA 4407 S. Peoria RIverside 2-7393

CORPUS CHRISTI 1620 S. Brownlee TUlip 3-7264

ODESSA 5425 Andrews Hwy. EMerson 6-6731

Lead Cable Submerged in Water Protected by Neoprene Jackets

Electric power cables protected with neoprene jackets have resisted corrosion and deterioration after nine years' service underground. Some of the cable was submerged in water continually. To determine condition of the lead sheaths used to protect the cable underground, resistance tests were made with a six-volt storage battery as current supply. Sheath-to-ground resistance of each neoprene covered cable was above 10 megohms per square foot—rated as excellent performance by the company's engineers.

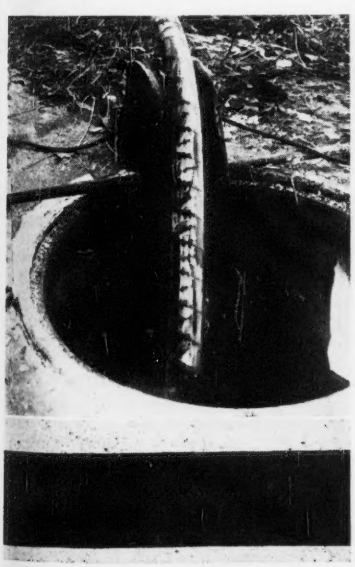
The power lines were three 69,000-volt cables installed in 1948 by the Philadelphia Electric Company in a substation. The last 325 feet of cable to the substation was laid underground, using lead-sheathed cables. The three lengths ran parallel down through a manhole and then up a slope where they fed into the station.

The underground ducts could have been graded to prevent collection of water, but this would have been an expensive and time consuming operation. Instead, lead sheathed cable was specified with neoprene jackets for protection against the corrosive water that would gather in the ducts. Extra cost of the jackets was estimated to be offset by the greater reliability of the cables.

The installed cables were insulated with layers of oil impregnated paper tape applied to a thickness of 0.315 inches. The insulation was protected by 0.175-inch thick lead sheath which was covered with a neoprene jacket. This jacket was applied in the form of a neoprene impregnated cotton fabric tape. The last layer of tape was cemented to the sheath; subsequent layers were heat-vulcanized to a total jacket thickness of 0.150 inches. Over-all diameter of the cable was 2.7 inches.

In 1957, expansion of the substation reqired that the cables be removed. As they were pulled from the manhole (shown in the top accompanying photograph), the cables were inspected carefully. The protective neoprene jackets showed no signs of deterioration even though immersed in water for nine years.

The white colored deposit seen in the upper photograph was easily removed to reveal the jacket's condition (bottom photograph).



NEOPRENE JACKETS for this 69,000-volt power cable successfully protected the lead sheath cable for nine years of total immersion in water. White deposit seen in top photograph was easily removed to reveal the good condition of the neoprene jacket (bottom photograph).

University of Utah Studies Vanadium Extraction From Oil

Isolation and extraction of vanadium and other metallic compounds from crude oil is being studied at the University of Utah. Vanadium is a commercially scarce metal that is vital to the manufacture of shock and heat resistant steel for jet engine parts and some rocket components.

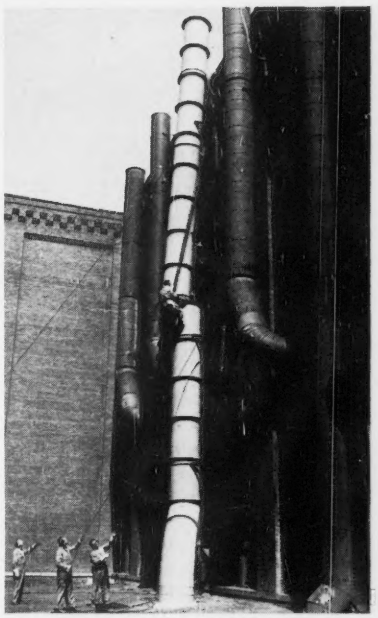
Vanadium may be invaluable to jet and rocket makers, but its presence in crude oil has been a problem to refiners. When vanadium-bearing crude is heated for distillation, the metal forms an extremely corrosive oxide that clogs tubes, eats into vessel walls and eventually forces shutdowns. Resulting repairs or replacement of damaged equipment is expensive.

This study is being conducted as Project 56 by James M. Sugihara under sponsorship of the American Petroleum Institute.

Three NACE Members Give Papers at European Meeting

NACE member Norman Hackerman, chemistry department chairman at the University of Texas, Austin, presented a paper titled "An Adsorption Theory of Corrosion Inhibition by Organic Compounds" at the European Symposium on Corrosion Inhibitors held recently at the University of Ferrara Institute of Chemistry, Ferrara, Italy. The meeting was sponsored by the European Federation of Corrosion.

Two other NACE members also presented papers at the symposium: J. I. Bregman of Chicago and Leo Cavallaro of Ferrara, Italy.



EIGHTY-FOOT STACKS for exhausting corrosive fumes from an automatic plater were fabricated of a rigid polyvinyl chloride. Made by Chamberlin Rubber Co., Rochester, N. Y., the exhaust stack's sections are 36 inches in diameter with one-eighth inch wall thickness. This stack was designed to have a service life of at least 15 years. Metal stacks on each side of the PVC stack have required replacement every three to four years because of corrosive action of the fumes.

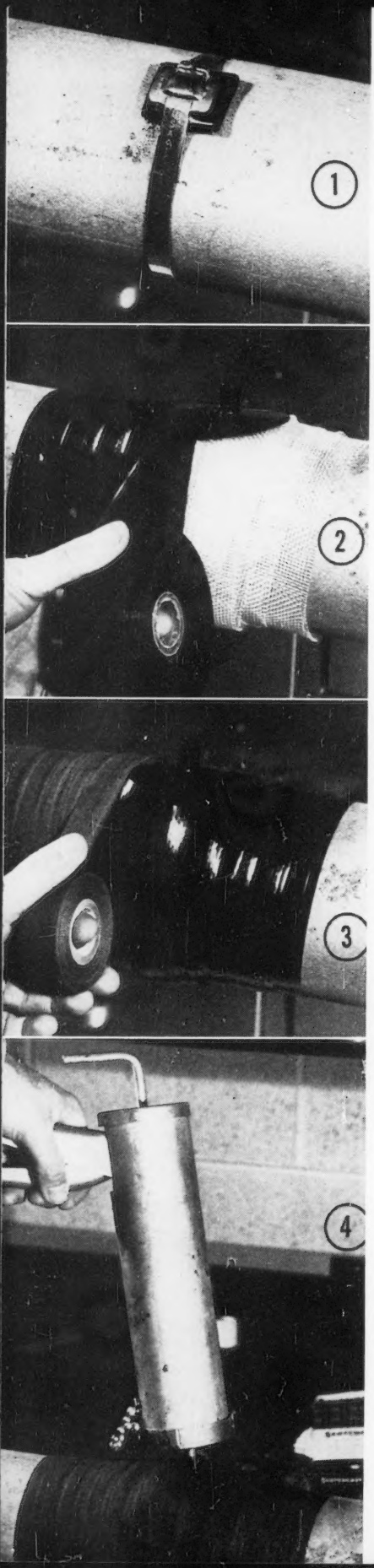
Polyester Resin Plugs Used in Meters

Adapter plugs made of chlorinated polyether were chosen over fluorocarbon and stainless steel plugs for use in a chemical metering device to indicate and control flow rate.

The plugs required accurate machining for proper fit and high dimensional stability. Stainless steel plugs tended to seize and gall. Steel also chipped or broke the Pyrex metering tube which is sealed to the meter by the adapter plugs. Fluorocarbon plugs solved the galling and breakage problem, but threads on this soft material were easily damaged.

Chlorinated polyether plugs solved these problems and are rated for use with acids, solvents, chlorides and mineral acids except concentrated nitric and sulfuric.

Plugs for the meter are machined from bar stock supplied by the Polymer Corporation of Pennsylvania, 2140 Fairmont Ave., Reading, Pa. The bar stock is made of Penton, a chlorinated polyether resin in molding powder form produced by Hercules Powder Co., Wilmington, Del.



Thermosetting Epoxy Resin Used For Rapid Pipe Repairs in Field

Speedy repair of leaks in any diameter pipe operating at pressures to 100 psi can be made with a thermosetting epoxy resin system.

The average workman, for example, can repair a small hole in a six-inch pipe in 10 to 30 minutes, according to Minnesota Mining estimates.

The resin used for repair is not affected by gasoline, fuel oil, crude oil or other hydrocarbons and resists most chemicals.

Developed primarily as a safe, reliable means of repairing gas transmission and distribution lines without the use of open flame and without removing the line completely from service, this new technique can be used for liquid piping repairs and for joining and patching plastic pipe.

After the pipe has been properly cleaned, the repair is achieved through the following steps as illustrated in the photographs at left:

Photograph 1: Area adjacent to the hole or crack is thoroughly cleaned and dried, using a wire brush and solvent wash to assure a maximum bond of the epoxy to the pipe. In most cases, an area eight inches on each side of the hole and around the entire circumference of the pipe is adequate. Then the hole is covered with a patch made of several folds of plastic tape. If pressure within the pipe is high, a steel pressure band may be applied to hold the patch as shown in Photograph 1.

Photograph 2: A screen-like tape called the spacer is wrapped around the pipe to cover an area six inches on each side of the hole. This serves as the porous framework or mold body for the resin. Cross-wound layers built to about one-eighth of an inch thick are sufficient for a pipe carrying 20 pounds pressure. Thicker applications are required for greater pressures. The injection fitting is placed over the spacer tape, then a plastic tape is used to cover the spacer wrapping, using a half-lap wind. This tape serves as the resin container or mold.

Photograph 3: A layer of cloth restricting tape is wrapped over the plastic tape to hold the resin under pressure while in the liquid state. Vent holes should be made with a knife point through both layers of tape at the outside edge of the spacer build-up and on top of the patch.

Photograph 4: After the resin is mixed in the divided, two-part container, the container is inserted into the gun. The gun's nozzle is inserted into the injection spout and the trigger pumped with smooth, slow strokes until resin droplets appear at the vent holes made with a knife. The gun is designed to produce about 100 psi at the nozzle.

The resin hardens in 30 minutes and is cured in less than two hours. Backfilling can be started 10 minutes after the patch is completed.

Additional information can be obtained from Minnesota Mining and Manufacturing Co., 900 Bush Ave., St. Paul 6, Minn.

International Congress Names Godard as Officer

Hugh P. Godard of Aluminium Laboratories, Ltd., Kingston, Ontario, Canada, past president of NACE, will be one of the vice presidents of the First International Congress on Metallic Corrosion to be held April 10-15, 1961, in London, England. Three other NACE members also will be vice presidents: F. L. LaQue and F. N. Speller of the United States and W. H. J. Vernon of England.

NACE member H. H. Uhlig of Massachusetts Institute of Technology will be one of the four guest lecturers at the congress. The others will be Y. M. Kolotyrkin of Russia, P. Lacombe of France and U. R. Evans of England.

Additional information on the program can be obtained by writing the International Congress at 14 Belgrave Square, London, S. W. 1.

AIME Book Published

A technical paper on creep and corrosion behavior of high strength zirconium alloys will be included in the Volume 10 of AIME's Special Report Series. Also included will be discussions on metallic moderators, cladding materials and other papers given at the October meeting of the AIME Metallurgical Society in Philadelphia.

Price of the volume is $5 to members and $7 to non-members. Additional information can be obtained from AIME, 29 West 39th St., New York 18, N. Y.

New Plants

Corning Glass Works has begun construction of a 400-acre research and engineering center near the company headquarters at Corning, N. Y.

•

Tube-Kote, Inc., Box 20037, Houston 5, Texas, has opened a new pipe coating plant in Edmonton, Alberta, Canada. The plant will have a coating capacity of about 8000 feet of pipe and tubing per day. Manager will be Joe H. Williams.

•

B. F. Goodrich Chemical Company has begun production of vinyl resins and compounds at its new plant in Long Beach, Cal.

•

Miles Chemical Company, a division of Miles Laboratories, Elkhart, Ind., plans to build a $2 million citric acid plant in Haifa, Israel. Scheduled for completion in late 1961, the plant will have an annual capacity of 1500 short tons of citric acid, 50 percent of which is slated for export, to make Israel a world leader in citric acid production. Miles Chemicals Israel Ltd., a new subsidiary of Miles Laboratories, will control the plant's operation.

•

One advantage of capitalism's free economy is shown in the price reduction of one flurocarbon resin which sells today at one-fifth its introductory price.

Steering Jets on Rockets Are Coated With Pure Gold

Steering jets built for advanced space vehicles are being coated with 0.04 mils of 99.8 percent pure gold for protection from radiation. Gold is used because of its reflectivity and density properties, claimed to reflect 95 percent of all energy radiation which might strike an orbiting vehicle's surface.

During the coating process, the steering jet is first sprayed with a thin coat of epoxy to help bond the gold to the metal surface. Solid gold and the jet are placed in a near-vacuum chamber. The gold is heated to 4712 F, at which temperature it vaporizes and spreads throughout the chamber to plate the controller jet. The unit is baked for 30 minutes in a special oven to complete the coating treatment.

Rail Welding System Cuts Time and Labor 40 Percent

A new rail welding system is claimed to cut welding time and manpower requirements by more than 40 percent, according to Linde Company, a division of Union Carbide Corp., 270 Park Ave., New York 17, N. Y.

The new system automatically handles the rail from storage racks through the welding process.

The American Railway Engineering Association has estimated that the average railroad saves $981 per track mile by installing continuous welded rail rather than rail with bolted joints.

•

About $200 million was spent on classical phonograph records during 1959 in this country.

Arc Temperatures Can Be Adjusted on Plasma Gun

A conversion kit to modify plasma spray guns so that arc temperatures can be adjusted between 300 and 30,000 F has been developed. The jet temperature is adjusted by changing the distance the rear electrode projects into the throat of the front electrode and by adjusting the insulated rod to which the rear electrode is mounted.

Hand-held plasma spray guns and the modification kit are manufactured by Plasmadyne Corp., 3839 S. Main St., Santa Ana, Cal.

International Pipeline Exhibition to Be April 9

Pumps and valves will be included in the Second International Pipes and Pipelines Exhibition to be held at Earls Court, London, beginning April 9, 1962.

Technical sessions will be conducted in conjunction with the exhibition, to present latest techniques in pipeline engineering, pipe and tube technology and pump and valve design.

Additional information can be obtained from Scientific Surveys Ltd., 97 Old Brompton Road, South Kensington, S.W. 7, England.

•

By 1975, the average after-tax income of USA families will be above $7000 a year—about $1500 above the present figure.

2 TOUGH PIPELINE PROTECTORS

RUBEROID ASBESTOS PIPELINE FELT...

Adheres to the pipe coating or enamel. Protects pipeline against root attack, soil distortion, and trench settlement which can occur from undergrowth in clay or rocky areas or where the soil is alternately wet and dry. Economical and long-lasting Ruberoid Pipeline Felt meets and exceeds the specifications of the American Waterworks Association and the National Association of Corrosion Engineers.

RUBEROID FLEXIBLE ROCK SHIELD...

A durable pipeline protector. Guards pipelines in rocky and swampy areas, and at river, railroad and highway crossings. Also used to make tough saddle pads for river weights or hold-down anchors. Can be applied either in two pieces or by the cigarette wrap method. ½″ or ¾″ steel strapping with aluminum seals or use of filament tapes insures permanent placement of the shield. Saves time and effort. Light weight cuts freight cost.

For specification details and samples, write The RUBEROID Co., Industrial Products Division, 500 Fifth Ave., New York 36, N. Y.

The RUBEROID Co.®

PIPELINE PROTECTIVE COVERINGS THAT LAST

Reinforced Plastic Pipe Used to Handle Corrosive Wastes

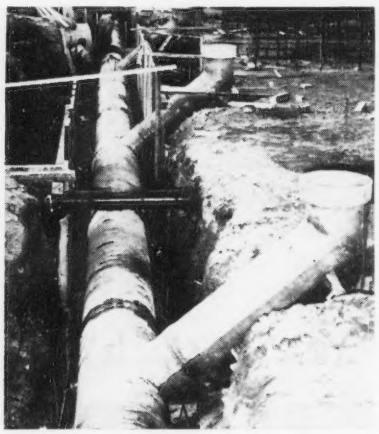
Plastic waste pipe made of reinforced thermosetting resins has been developed to give high strength, positive sealing and resistance to corrosive wastes in the metalworking, chemical, texile and allied indusries.

The plastic waste pipe installation shown in the accompanying photograph handles waste pickling liquor with 10 to 15 percent dilute sulfuric acid. The main line measures 48 inches in diameter and is over 300 feet long. The laterals are 24-inch diameter and join with the main at factory installed 90-degree branch entries.

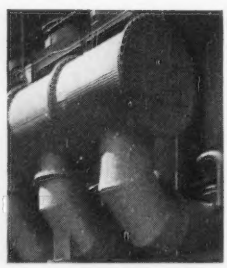
Fabricated in 10-foot lengths to reduce the number of joints, the pipe has bell-and-spigot construction for job-site joints with resins and random fiberglass mat for positive sealing.

Faster installation at lower cost than conventional tile or steel pipe is claimed for this plastic pipe because each section is light enough in weight that two men can lift and set each section in place without lift trucks, cranes or other mechanical equipment, according to the manufacturer, Ceilcote Company, 4832 Ridge Rd., Cleveland 9, Ohio.

Depending on surface traffic, this pipe can be encased in concrete, set in a concrete cradle and backfilled with sand or laid on sand and backfilled with sand.



REINFORCED PLASTIC pipe made of thermosetting resins is shown being installed as pipe to handle waste pickling liquor with 10 to 15 percent dilute sulfuric acid. The main line is 48 inches in diameter and over 300 feet long. The laterals are 24 inches in diameter and connected to the main with factory installed 90-degree branch entries.



Reinforced Plastic Manufacturers and Engineers

Since 1950

chemical tanks, pipe and ducts, custom laminating and molding, translucent and structural panels

Cahill Plastics

P. O. Box 12056

Houston 17, Texas

MIssion 5-6051 JAckson 3-0041

BOOK NEWS

Handbook of Metal Protection. (In German.) By Wilhelm Wiederholt and Johannes Elze. 1960. 900 pages, 4⅝ x 6⅝ inches, cloth, flexible. Wissenschaftliche Verlagsgesellschaft M.B.H., Stuttgart, Germany. Per copy, DM 78.

A comprehensive survey of the metals protection field, divided into the following major subdivisions: Fundamentals of metallic corrosion, conclusions about the behavior of metal for corrosion protection and for preventive and protective measures, active corrosion protection, passive corrosion protection, examination of corrosion continuity and protection efforts, accident prevention and protection of workers, literature.

The book is liberally illustrated with line and halftone figures, includes 80 tables. Contests are very detailed. Literature sections includes books, peirodicals, an alphabetical author index of several hundred technical articles and a 26-page alphabetical subject index.

Anti-Corrosion Manual. Third Edition. 1950. 398 pages, 8¼ x 11 inches, cloth, including advertising. Corrosion Prevention and Control, 97 Old Brompton Rd., London S.W. 7, England. Per copy, Pounds sterling 3 plus 3 shillings and sixpense for packing and shipping.

Contents include: Corrosion in industry: motors, food manufacturing, stainless steel knives; corrosion in the oil industry;

Corrosion resistant materials and applications: Tabulated data on resistance of materials, aluminum, asbestos, cements, ceramics, copper, glass, and others;

Surface Preparations: Degreasing, chemical descaling, salt descaling, chromate and phosphate treatments;

Protective coatings: paints and primers, aluminum, lead, resin-based, zinc-rich.

Mastics, metallic coatings, spray painting methods, pipe coatings and tapes, protective packaging, water treatment, testing, cathodic protection.

There is an index of British standards and a subject index.

Product Engineering. Design Digest Issue. September, 1960. 554 pages, 8¼ x 11¼ inches, paper (including advertising). McGraw-Hill Publishing Co., 330 W. 42nd St., New York 36, N. Y. Per copy, $0.50.

A compilation of information useful to design engineers working in the industrial field collected from 76 periodicals, technical papers from 35 technical organizations. Contents are divided into general engineering, metals and alloys, non-metallic materials and finishes, fabrication and production practices, power transmission, mechanical parts and design analysis, fastening and joining, motors, engineers and controls; electrical and electronic components and hydraulic and penumatic equipment.

There is an extensive subject index. There are numerous graphs and tabulated data.

Engineer's Handbook. By W. A. Thomas, H. A. Spalding and Zarko Pavlovich. 1960. 192 pages, 2¾ x 5½ inches, flexible. Ottenheimer Publishers, Inc., 4805 Nelson Ave., Baltimore 15, Md. Per copy, $0.90.

A collection of formulae, illustrated mechanical principles and tabulated data related to mechanics, heat, hydraulics, piping, electricity, surveying, costs, mining, chemistry. Alphabetical subject index.

Five Articles Concerning Natural Gas (in Spanish), 101 pages, 7⅞ x 11½ inches, paper, 1960. Published in Buenos Aires, Argentina. Source and price unknown.

Consists of five technical papers presented by engineers at a symposium on natural gas held at Buenos Aires in September 1959 at the Fourth Argentine Engineering Congress.

The articles are: Past, Present and Future of Gas in the National Energy Scheme, by Esteban R. Perez; Formulas for Calculating the Transmission of Natural Gas Through Pipes by Antonio Barbato; The Gampo Duran-Buenos Aires Gas Transmission Line by Ricardo A. Bazzi and Ruben P. Ginesta;

Use of Natural Gas from Argentine Petroleum-Producing Strata by Moises Juri and Conversion to Natural from Coal Gas of 420,000 Users in Buenos Aires by Cesar Augusto de Urquiza and Jacobo Epstein.

1958-59 Abstracts of Theses. 288 pages, paper bound. Sept. 23, 1960. Publications Office, Massachusetts Institute of Technology, Cambridge 39. Per Copy, $3.50.

Titles of theses submitted for engineers' and masters' degrees during the year and abstracts of theses presented in the departments of aeronautics, biology, chemical engineering, chemistry, civil and sanitary engineering, electrical engineering, food technology, mathematics, mechanical engineering, metallurgy, nuclear engineering, physics and others are published.

Microfilms and photoprints of theses can be obtained.

Over a million new homes were purchased in 1959 by USA residents at a total cost of $18 billion.

* Practically Perfect!

HUMBLE COREXIT®

Save time and money previously lost to internal corrosion: use Humble COREXIT . . . COREXIT effectively and economically prevents internal corrosion in pipe still overhead, distillation towers, vapor recovery systems and other refining units. COREXIT will reduce or completely eliminate plugging or fouling. This protection against sludge, scale and corrosion cuts non-productive downtime to a minimum. For complete information on technical services and products, contact your Humble salesman.

HUMBLE

HUMBLE OIL & REFINING COMPANY

Plant Inspection Set Up for Oil Field Tubing

Possible Corrosion Failures Are Caught Before Pipe Is Used

Rapid and thorough inspection of oil field tubular goods before delivery to the customer is being made by a magnetic induction technique which gives a complete inspection of each piece of pipe, externally and internally. Called Amalog, the new inspection procedure is operated by Tuboscope Company, P. O. Box 808, Houston 1, Texas.

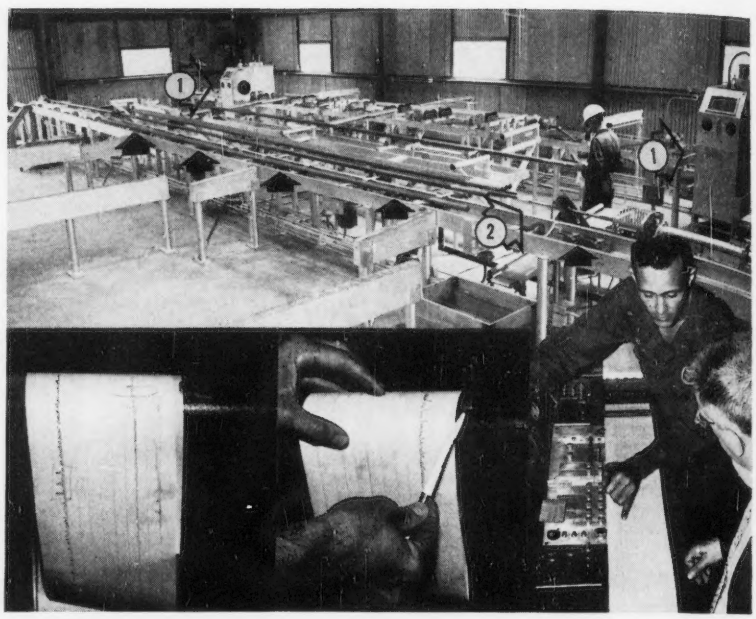
This pipe inspection service has been set up as a plant-type operation at Walker's Mill near Pittsburgh, Pa., so that a customer can order pipe from one of the major pipe mills in that area, have it delivered by rail or truck to the inspection plant and after inspection have it shipped to the field. Because the inspection plant is within the railroad switching limits of most Pittsburgh pipe mills, additional freight costs are economical.

If defective lengths of tubing are found during the inspection, replacement agreements sometimes can be made between the pipe mill and customer before final shipment is made.

Thus, when a customer orders pipe from one of the mills in the Pittsburgh area, he can specify inspection before delivery. The pipe is switched to the inspection plant, unloaded and then automatically fed through each inspection step.

After inspection, the pipe which is determined to be free of defects according to API or customer standards is reloaded and shipped according to the customer's request. Thus, the customer saves the expensive time loss and shipping costs of returning defective pipe from the field and minimizes costly service failures caused by corrosion attacks or mechanical factors at defective areas in the pipe.

This inspection service has been set up so that customers can be assured of receiving pipe that can be put into service with a minimum of defects that could cause failures. Most pipe delivered directly from the mill usually is inspected only by visual means. Therefore defects which do not cause visible discontinuities are not caught. Some plants use a magnetic particle method for more thorough inspection, but this method checks only the external surfaces.



AUTOMATIC EQUIPMENT carries pipe lengths from the yard into the inspection plant where the up-set ends are sandblasted (at Arrows One in the photograph), then the pipe is magnetized by passing an insulated bar (Arrow Two) through the pipe's entire length. A large d-c current conducted through the bar induces a residual magnetic field in the pipe. Then the pipe passes over search coil stations (indicated by the solid black arrows) which detect discontinuities in the pipe and record these defects on a strip chart recorder (lower right section of photograph). The two photograph sections at bottom left show the recorded discontinuities on two pipe lengths. The pits can be seen to the right of the strip chart sections.

Inspection Procedures

After the pipe is unloaded from the rail cars at the inspection plant, automatic equipment feeds each length into the plant. First, the up-set areas at the ends of each piece of pipe are sandblasted to remove the shellac coating and scale sot that proper inspection can be made. (See arrows numbered one in the photograph.) Each piece is magnetized by passing an insulated bar through the full length of pipe (arrow two.) A large d-c current conducted through the bar induces a residual magnetic field into the tube for inspection purposes.

Thus magnetized with flux lines running circumferentially, defects in the pipe can be detected by search coil stations (indicated by solid black arrows) because most defects are oriented longitu.linally. The pipe is rotated so that the entire length of each pipe passes over two or more of the search coil stations. When a defect passes over a station, an indication of the defect is recorded on a strip chart (lower right in photograph) as a result of the change in the magnetic flux lines caused by the defect. Several different recordings are made simultaneously on each length so that the operator can locate the defect and determine its general characteristics. A permanent record on each string is made on the chart.

The search coil stations record and locate seams, overlaps, slugs, roll-ins, cracks, laminations, harmful body wall eccentricities and other discontinuities which could cause mechanical failure of the pipe in the field. These defects also could be areas of concentrated corrosion cells.

Two large external pits in a pipe are shown in the bottom photographs with reproductions of the pits recorded on the strip chart.

Because discontinuities in the pipe, whether external or internal, cause magnetic flux line orientation to be changed at the defective area, the Amalog equipment checks the entire pipe length with one pass over the coil stations. The older inspection method of using magnetic particles which were sprinkled over the pipe did not detect internal discontinuities.

After the over-all length of pipe is inspected and if the pipe is up-set, a 3-foot area at each end is inspected optically and mechanically for transverse cracks. This is accomplished by inducing longitudinal flux lines with a coil collar and by applying magnetic powder. Up-set defects generally are oriented circumferentially, thus causing changes in the orientation of longitudinal flux lines. An optical instrument is used to check the internal surface of the end areas.

This special inspection of the end areas is necessary because the Amalog's search coil stations cannot follow the change in the pipe's outside diameter.

Pipe sizes to 13⅜ inches in diameter can be handled by the Amalog equipment.

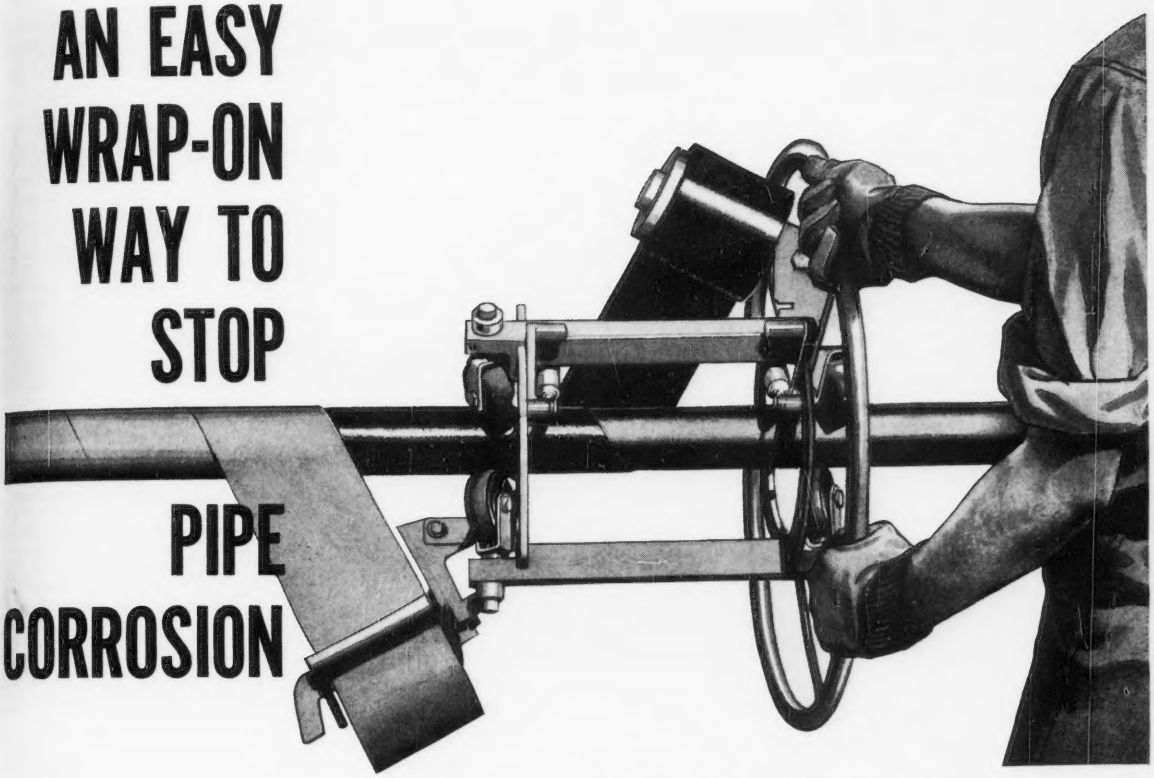
Chemistry Congress Held

One day of the October 23-30 International Congress of Industrial Chemistry held in Barcelona, Spain, was devoted to discussions on corrosion problems. This one-day symposium was sponsored by the European Federation of Corrosion.

•

About $300 million worth of high fidelity sound equipment was sold in the United States during 1959.

AN EASY WRAP-ON WAY TO STOP PIPE CORROSION



Chasekote*

Pressure-Sensitive Polyethylene Tape has an extra-heavy adhesive mass that clings to clean pipe on contact . . . makes a perfect, permanent bond that rustproofs, waterproofs and insulates pipe against all types of corrosion.

Chasewrap*

Protective Overwrap is a tough, wrinkle-free outerwrap that shields against abrasion, wear, and physical damage to the tape. Wraps simultaneously with the tape. Superior to rag and felt wraps, yet far lower in cost.

*Trade name of Chase & Sons, Inc., long-famous for protective and insulating tapes for electrical wire and cable

The new CORR-PREV Pipe Coating Team comes in easy to handle tape form. It goes on pipe faster and lasts longer than corrosion-proof paints. It's cleaner and simpler to apply, too, than hot tar coats. And most important, this new CORR-PREV Team offers all the cost-cutting, pipe-saving advantages of *polyethylene* tape.

With CHASEWRAP Abrasion-Resistant Overwrap and Chasekote polyethylene tape, you get the easiest and best pipe protection at *lowest applied cost!* There's no heating, drying, clean-up or shut-down time. Each roll is factory-uniform in thickness and quality. And all coating materials — including rental of high-speed applicators — are available from one reliable source. Want samples? Specs? Prices? Write **CHASE & SONS, INC., 26 Spruce St., North Quincy, Mass.**

Refineries & Gathering Systems

Public Building Lines

Oil & Gas Transmission Lines

(CORR-PREV) DIVISION

Highway and Airport Conduit & Pipe

Utility Distribution Systems

Chemical & Industrial Plant Piping

FOR YOUR ELECTRICAL INSULATION PROBLEMS SPECIFY CHASE FRICTION, PLASTIC, RUBBER, NEOPRENE AND BUTYL TAPES

Reinforced Polyester Resins Resist Corrosive Fume Attack

Three case histories given below involving disposal and exhaust of corrosive fumes in chemical processing plants indicate the applicability of equipment made of polyester resins reinforced with fiberglass for corrosion resistant service.

At one chemical plant in the eastern United States, a stainless steel system for venting a reactor required extensive repairs after several months service in mixed acid fumes at 200 F. Because of additional corrosion at the welds made for repairs, the steel system failed in 11 months.

After aluminum ducts failed to solve the corrosion problem, a duct system made of polyester resins was installed and has given four years' service without corrosion damage.

A second case involves 18-gauge nickel ductwork in a dye plant. This equipment gave 14 months' service under the effects of such corrosive chemicals as wet chlorine, hydrogen bromide and hydrochloric acid in combination with organic solvents.

The nickel ducts were replaced with rubber lined steel which lasted less than a year. In the same service, a polyester resin duct system has been reported still in operation after six years' service.

A third case history is a 36-inch diameter horizontal header made of 2-inch cypress staves. Several 18-inch diameter wood ducts were connected into the header, then to a 30-foot scrubbing tower. This system sprang leaks and required expensive supports. Replacement of the whole system or its parts was necessary every two years. The polyester ductwork used to replace this wooden equipment has given service without leaks and downtime, according to the plant superintendent.

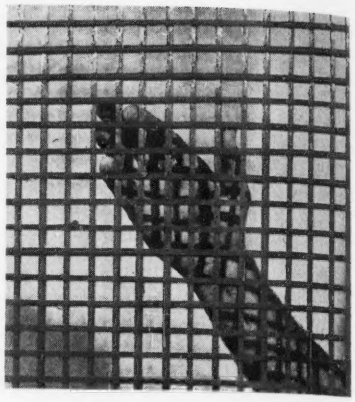
These systems were made of a resin called Hetron, produced by the Durez Plastics Division of Hooker Chemical Corp., North Tonawanda, N. Y.

Papers Given on Corrosion Study Uses of Isotopes

Three papers on use of radioisotopes in corrosion studies were presented by Oak Ridge National Laboratory personnel at recent European conferences on nuclear reactions. The papers dealt with radio-tracer techniques in the physical chemistry of the corrosion process and its inhibition, radio-tracer techniques in the study of corrosion by molten fluorides and radioisotopes as tracers for reactions in molten fluoride media.

High Temperature Meeting

A conference on high temperature materials with special emphasis on applications above 1600 F will be held April 26-27, 1961, at the Hotel Pick-Carter in Cleveland, Ohio. The conference will be sponsored by the AIME Cleveland Section.



CORROSION RESISTANT fencing or protective screening can be made from a new material composed of continuous strands of glass rovings and polyester resins. Designed for maximum moisture absorption of 0.05, this fencing has pigmented resins to permit color variations for safety and color coding. It can be cut by tinsnips, hacksaw or hand powered tools. It is recommended for use as guards and covers around plating tanks, acid baths, machinery and electrical installations. It is manufactured by Firmaline Products of Crompton & Knowles, Midland Park, N. J.

PERIODICALS

Boletim do IBP. Vol. 1, No. 1, 1960 trimonthly. 8⅜ x 10⅞ inches, 40 pages and cover. Published by Instituto Brasilero de Petroleo, Av. Pres Vargas 417 A, Grupo 2102, Rio de Janeiro, Brazil. Price not indicated.

A magazine designed for circulation among persons in Brazil concerned with the petroleum industry. Includes news items and technical, statistical and economic information pertaining to Brazil's petroleum industry.

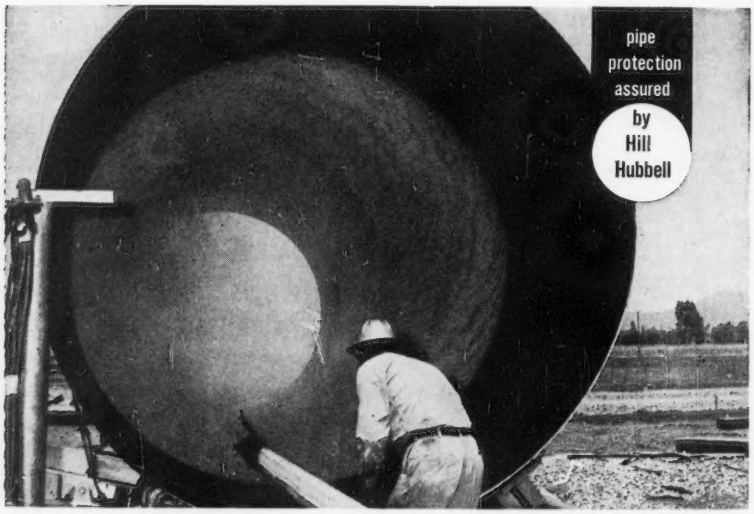
Technical Bulletin, Englehard Industries, Inc. Vol. 1, No. 1. Quarterly. June, 1960. 48 pages and cover, 7¼ x 10 inches. Technical Information Dept., Englehard Industries, Inc., 75 Austin St., Newark 2, N. J. Gratis.

A quarterly publication designed to inform manufacturing executives, scientific and technical men of research results and new product developments in fields served by Englehard Industries, Inc. Contains technical articles from research department, including "Developments on High Temperature Thermocouples Using Noble Metals" by E. D. Zysk.

One section covers patents issued to the company and a second patent abstract section covers patents on application of platinum metals and gold.

Ocean Environment Study

A long-term study of the oceans as an environment for man-made structures is underway as a cooperative project supported by funds from the Army, Navy and Air Force. The project, under auspices of the Prevention of Deterioration Center, is expected to include a general survey of the field, a study of ship fouling, boring organism and corrosion.



record-breaking tunnel job *fully protected*

For lifelong dependability in a vital power generating installation, these 13-foot diameter penstocks were lined, coated and wrapped by Hill Hubbell corrosion protection experts.

Whether yours is a large or small diameter installation, the best possible protection you can specify is Hill Hubbell, the name synonymous with quality in mill coated-and-wrapped pipe.

Specify Hill Hubbell wrapped pipe on your next job . . .

HILL HUBBELL

3091 MAYFIELD RD. · CLEVELAND 18, OHIO · YELLOWSTONE 2-7535

how to keep metal away from petroleum . . .

UNICOR®

. . and why it pays, in terms of both product and equipment!

Petroleum products and metals are apt to wage war. Life-robbing corrosion attacks the metal, while profit-stealing contamination downgrades the product. But there's an easy way to forestall such trouble. Use UNICOR.

This potent, film-forming, oil-soluble corrosion inhibitor plates out on metal, stands off corrosion by crude or refined petroleum. Only 10 to 20 parts of UNICOR per million of product assures lasting protection against corrosion in pipelines, refinery vessels and tanks.

Purer product, longer equipment life, reduced downtime for maintenance and cleaning, lower power costs . . . all result from using UNICOR. For detailed information and samples write our Products Department.

See our PSE*

Correct selection and most effective use of petroleum inhibitor and additives involves expert analysis and consideration of many factors. As specialists for over a quarter-century, UOP is able to provide unparalleled field service, brought to you by a member of our staff of *Product Sales Engineers. For detailed information on the UOP family of superior inhibitors and additives call or write our Products Department.

UOP®

UNIVERSAL OIL PRODUCTS COMPANY
30 Algonquin Road, Des Plaines, Illinois, U.S.A.

WHERE RESEARCH TODAY
MEANS PROGRESS TOMORROW

Thermoelectric Power Used for Heater Fans and Lighted Buoys

Thermoelectric generators have been developed to power lighted buoys and to operate a fan to circulate warm air in a gas fired wall heater.

The thermoelectric generator powering the navigation buoy (shown in accompanying photograph) derives its power from burning propane fuel. It is designed to deliver 200 watt hours for each pound of fuel at a cost of about 15 cents per kilowatt hour. Present costs for battery powered buoys is about $6 to $10 per kilowatt hour. Battery operated buoys deliver about 10 watt hours for each pound of batteries.

Power for the fan in the wall heater is derived directly from the heater's combustion chamber.

These thermoelectric generators convert heat energy into electrical energy without moving parts. Current is produced when a junction of two dissimilar materials are heated.

Future applications of thermoelectric generators may be to provide a stand-by electrical power for homes during emergencies.

The buoy and wall heater generators were developed by Minnesota Mining and Manufacturing Co., St. Paul 6, Minn.

THERMOELECTRICITY to power the light for a navigation buoy (left) is provided by the thermoelectric generator (right) which operates on propane fuel. This generator is designed to provide cheaper power than conventional battery operated buoys.

FOCUS
on
CATHODIC PROTECTION
Three Technical Topics and three articles in the Technical Section of the January issue will be on a variety of cathodic protection subjects.

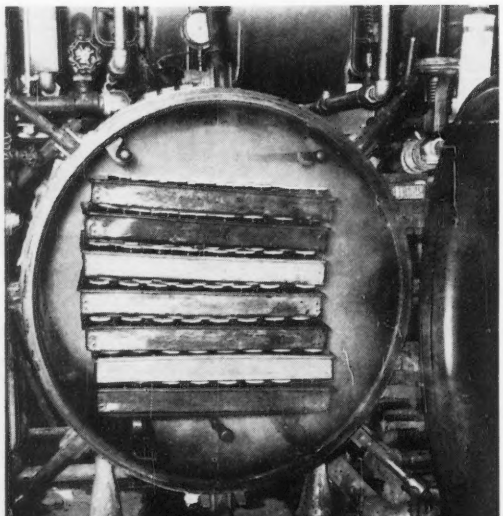
VINYL PLASTIC sheet pre-fabricated into one piece measuring 21,680 square feet was used for a water reservoir liner at Lancaster, Cal. The liner was laid over bare, tamped earth to serve as a retainer for two million gallons of city water. The 20-feet deep reservoir is 220 by 77 feet. Folded like a road map, the liner was laid down the middle length of the reservoir floor and pulled up the sloping sides. A savings of $5000 was estimated over conventional construction methods. General contractor for the project was Conkle Construction Company of Rosemond, Cal.

•

The sale of books in the United States totalled $630 million in 1959.

•

The sale of books in the United States totalled $630 million in 1959.



Retort oven where Z.R.C. coated pans are subjected to temperatures of 240° F. (under 21 lbs. pressure) and quick cooling via quenching bath. Cycle also includes conveying, washing, and stacking. Light gray pans are those treated with Z.R.C.

No glamour — just facts

about Z.R.C.® (Zinc Rich Coating)

Maine Canned Foods, Portland, Maine, has greatly prolonged the life of their hot dip galvanized retort pans by recoating them with Z.R.C. at the first sign of rust. "We're delighted with the way Z.R.C. stands up" is their report.

Renewing hot dip surfaces that have started to wear (or damaged through abrasion, welding, etc.) is just one of hundreds of possibilities open to Z.R.C. users. It's easy to apply by brush, spray or dip; comes ready for use in a single container, dries quickly, requires no special surface preparation.

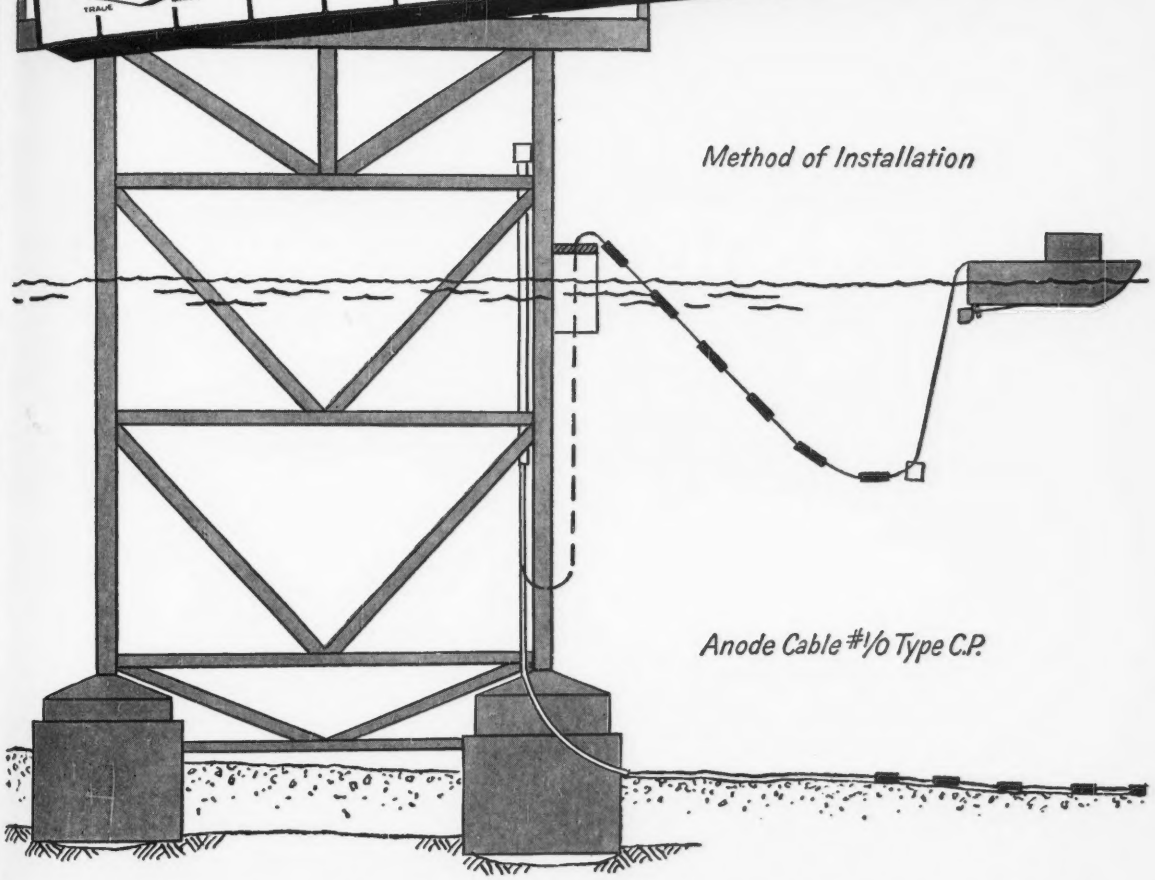
Z.R.C. utilizes an **epoxy** resin, contains 95% pure zinc in the dried film, will withstand over 3000 hours of salt spray testing and passes the Preece Test. Cost—about 1½¢ to 2¢ per sq. ft. For full details . . .

THE SEALUBE COMPANY

WAKEFIELD, MASS.

Anode notes from

National Carbon Company



PROTECTION OF A $4,750,000 OFFSHORE DRILLING RIG

Corrosion engineers of a large oil company decided to use impressed current cathodic protection on the underwater foundation of an offshore drilling rig.

Six strings of 10 "National" NA Graphite Type QA Anodes* were used to provide a distributed anode bed. They were assembled on 1/0 C.P. cable at fifteen foot spacings. Anode strings were placed radially around the platform on the sea bottom with the first anode approximately 200 feet from the platform base. The anode strings are held in place by 12"x12"x16" concrete anchor blocks at the end of each string.

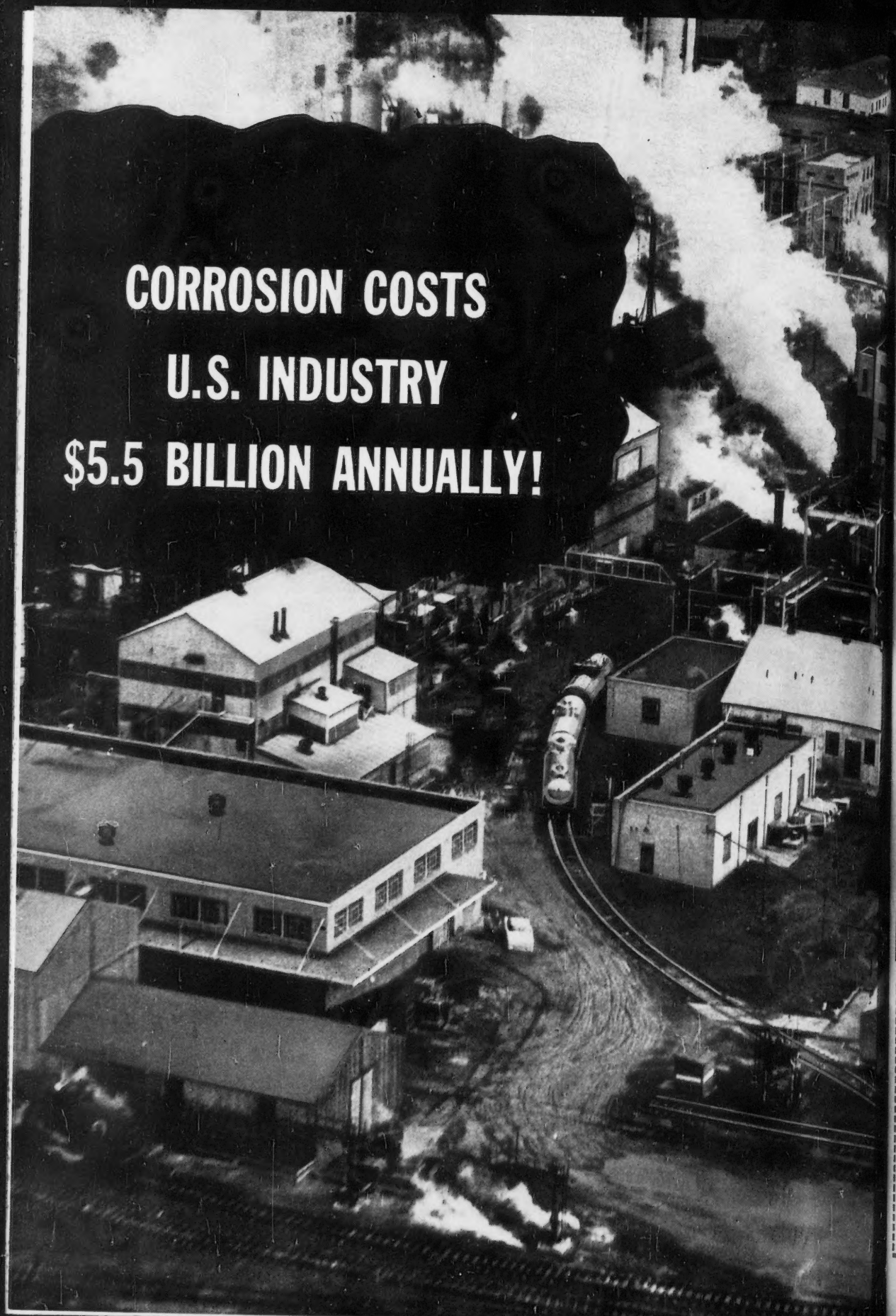
"National" NA Graphite Anodes were selected because of proved long anode life (about 0.1 lbs./amp. year consumption in free moving salt water) and low initial cost.

*Anodes were sold by The Vanode Company, Pasadena, California

"National", "N" and Shield Device, and "Union Carbide" are registered trade-marks for products of

NATIONAL CARBON COMPANY
Division of Union Carbide Corporation • 270 Park Avenue, New York 17, New York
IN CANADA: Union Carbide Canada Limited, Toronto

UNION CARBIDE



Corrosion
can indust
corrosion
or $9,468
costing yo
More a
complete P
coatings
corrosion.
20 differe
specific ty
ordinary t
Pitt Cr

PITT C

PITT C

Name
Compa
Street
City

Now You Can Control 97% of All Your Corrosion Problems with this Proven PITT CHEM® Coating System!

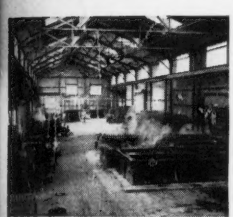
Corrosion is one of the biggest profit robbers in American industry today. It is conservatively estimated that corrosion costs U.S. industry $5.5 billion annually . . . or $9,468 per minute! How much is this enormous waste costing *your* plant?

More and more corrosion engineers are turning to the *complete* PITT CHEM System of thick-film, cold-applied coatings for efficient long-lasting protection against corrosion. The PITT CHEM system is composed of over 20 different coatings, each formulated to control a specific type of industrial corrosion—from the most ordinary to the most severe—at minimum cost.

PITT CHEM Tarset, Tarmastic and Insul-Mastic are tough, *heavy film* coatings that outlast conventional maintenance paints 10 to 20 times. You measure their protection in *decades*, not years. They can be cold-applied by brush, spray gun or roller. No other family of protective coatings can solve so *many* of your corrosion problems so *economically*.

For more information, mail the coupon below. Then consult your nearest PITT CHEM Distributor—he's listed in the "Yellow Pages." Or call Pittsburgh Coke & Chemical Company in Pittsburgh, New York, Chicago, Houston or Los Angeles. A PITT CHEM Corrosion Engineer will be glad to discuss your corrosion problems without obligation.

PITT CHEM TARSET®

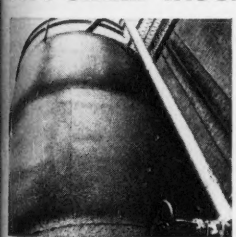


The original, patented coal tar-epoxy coating, Tarset is being used throughout industry to solve corrosion problems that were once considered "impossible." This revolutionary cold-applied coating is ideal for the protection of underground storage tanks, pickling tanks, high temperature steam lines, waste tanks and similar equipment.

PITT CHEM TARMASTIC®

PITT CHEM Tarmastic coatings are a series of coal tar protective coatings designed to meet a wide variety of corrosive conditions at moderate cost. Their protective ability has been proven by years of service on concrete, stone and masonry surfaces, cooling towers, fan housings, tank exteriors, potable water systems and similar equipment.

PITT CHEM INSUL-MASTIC®



A series of high quality Gilsonite-asphalt mastics recommended for economical, long-lasting protection against moisture and atmospheric corrosion. Widely used as a weather and moisture barrier over metal buildings and equipment. Insul-Mastic insulating cork mastics provide good heat loss reduction and condensation control.

PITT CHEM PIPELINE ENAMELS

PITT CHEM Coal Tar Pipeline Enamels protect oil and gas transmission and distribution lines throughout the United States. These proven, high quality enamels are geared to meet a wide variety of underground service conditions and are backed by experienced technical field service.

Send for Your Free Copy of this

INDUSTRY CORROSION DATA FILE

Includes a survey of corrosion problems in general industry, data on PITT CHEM Coating Systems and a coating selector guide.

Name_____ Title_____

Company_____

Street_____

City_____ State_____

PROTECTIVE COATINGS DIVISION

PITTSBURGH CHEMICAL CO.

GRANT BUILDING PITTSBURGH 19, PA.

A Subsidiary of PITTSBURGH COKE & CHEMICAL CO.

1180

Equipment Services NEW PRODUCTS Materials Literature

Abrasives

Abrasive crystals designed to meet the critical requirements of the electronic and semiconductor industry for ultra high polished surfaces are manufactured by Geoscience Instruments Corp., 425 Park Ave., New York 22, N. Y. Marketed under the name Corunda, the metallographic polishing alumina are available in grades for hard and soft metallographic specimens and special applications such as spectroscopy and petragraphic thin sections.

•

Improved cutting techniques and new applications for the use of air-abrasive units are discussed in a bulletin available from S. S. White Industrial Division, 10 East 40th St., New York 16, N. Y. The bulletin describes the Airbrasive unit used as a cutting tool on germanium, glass, silicon, oxide coatings, ceramics, plastics and other fragile, hard-to-cut materials.

Biocides

Non-corrosive liquid organic biocides for addition to industrial cooling water have been developed by Dearborn Chemical Co., Merchandise Mart Plaza, Chicago 54, Ill. Called Dearcide, they are compatible with sulfates, phosphates, chlorides or carbonates in water and are recommended for use in fresh and brine water against sulfate reducing bacteria which are one of the primary causes of corrosion and plugging in water flood systems.

•

Effective against most microorganisms, Hagan B-2, a biocide for use in oil field operations, is described in a bulletin available from Hagan Chemicals & Controls, Inc., Hagan Center, Pittsburgh 30, Pa. This biocide provides protection against corrosion by forming a protective organic film on metal surfaces, according to the manufacturer.

Cathodic Protection

Diversified corrosion control to include cathodic protection, chemical treatment, scale treatment, coating applications and paraffin treatment is part of the expansion program begun by Corrosion Rectifying Co., Inc., 5310 Ashbrook St., Houston 36, Texas. A division office is located at 907 Fairway St., New Orleans, La.

•

A replaceable head for a soil resistivity prod bar has been designed to make the prod bar last five times longer. Conventional hexagonal prod bars must be discarded when wear reduces the tip size. Developed by Agra Engineering Co., 1537 East 10th St., Tulsa, Okla., the Agra prod is a single bar incorporating two electrodes.

Coatings, Metallic

Three-year tests on steel fasteners coated with aluminum have shown good resistance to corrosive industrial atmosphere, according to Bethlehem Steel Co., Bethlehem, Pa. Called Bethalume, the coating is obtained by immersing an iron or steel fastener in a molten bath of pure aluminum. Exposure tests in Hawaii and on the West Coast indicate the coating also is suitable for marine atmospheres.

•

Zirconia coating is available for application by Plasmarc plating process, developed by Linde Company, division of Union Carbide Corp., 270 Park Ave., New York 17, N. Y. This process is for applying coatings and for fabricating shapes, using materials having ultra-high melting points.

Heat Exchangers

Wrought iron radiant heating system embedded in a concrete floor slab has been installed in a 77-foot high church. Pipe for the installation was supplied by A. M. Byers Co., Clark Bldg., Pittsburgh, Pa.

•

Heat transfer and process equipment such as brine coolers, titanium chloride coolers, organic vapor condensers, welded steel heat exchangers and pressure vessels are described in a bulletin available from Niagara Weldments Inc., 55 Portage Rd., Niagara Falls, N. Y. The company formerly was known as Niagara Welding & Boiler Works, Inc.

Inhibitors

Technical data sheets on inhibitors for scale and corrosion control in water-hydrocarbon systems, squeezing, batch dumping, and paraffin control are available from Visco Products Co., 1020 Holcombe Blvd., Houston 25, Texas.

•

Oil field acidizing with addition of proper inhibitors to prevent corrosion is described in a brochure published by Dowell Division of Dow Chemical Co., P. O. Box 536, Tulsa, Okla. A data sheet also is available on Depban, a chemical mixture designed to retard or prevent paraffin build-up on metal surfaces in wells.

Instruments

Concentrations of dissolved oxygen can be measured in fluid systems including sewage, biological, natural and fresh sea water and some organic media by use of an instrument, according to the Jarrell-Ash Co., 26 Farwell St., Newtonville 60, Mass. Battery operated with transistorized amplifier, the instrument gives readings based on current produced by reduction of oxygen at a platinum electrode.

•

Corrosion meters designed for laboratory and field work are being produced by Crest Instruments, 11808 S. Bloomfield Ave., Santa Fe Springs, Cal., a division of Magna Products. Called the Model CK-2 Corrosometer, the instrument weighs 11 pounds and is housed in an aluminum case. It has a standard probe, a reel stored probe cable and a mercury-battery power supply with an integral battery test circuit.

Lubricants

A solid film lubricant for application on metal surfaces to prevent galling, seizing, fretting, corrosion, cold welding and similar friction problems is described in a bulletin available from Hohman

MCC the acid tamer NEW

a GIANT STEP FORWARD for ACID CLEANING and PICKLING

NOW ALUMINUM or galvanized can be cleaned by the hydrochloric solution method, without any harmful corrosive effect.

MCC acid corrosion inhibitor, a NEW universal additive for all acids, except nitric, improves acid cleaning solutions for all metals, except magnesium, by inhibiting the surface destroying corrosive effect of the acid without imparing the cleaning qualities. MCC the universal additive is a giant stride forward in acid cleaning techniques.

ALUMINUM BOLTS immersed in identical acid strength for 24 hours. Solution using MCC inhibitor showed no visible effects.

WRITE FOR BULLETIN No. 105

devlimco

DEVELOPMENTS UNLIMITED INCORPORATED
328 BROADWAY PASSAIC, NEW JERSEY

Plating & Mfg. Co., 814 Vermont Ave., Dayton 4, Ohio. Called Surf-Kote A-1290, this lubricant contains a molybdenum disulfide compound and can be applied by spray, dip or brush.

•

Formulas for soluble cutting oil concentrates are described in a bulletin released by Atlas Powder Co., Wilmington 99, Del. One formulating described is designed to form emulsions at room temperature in waters of varying hardness.

•

Non-corrosive, non-carbonizing and non-burning characteristics are claimed for a new lubricant called No-Flame, developed by Bel-Ray Company, Farmingdale, N. J. This lubricant also is claimed to maintain its stability under temperature and pressure extremes.

Mergers

Kawecki Chemical Co., Boyertown, Pa., has purchased 50 percent of the common stock of Penn Rare Metals Inc., Revere, Bucks County, Pa. The companies will continue independent production and research operations.

•

Corite-Reynolds Corp., 455 Jarvis Ave., Des Plaines, Ill., is a new organization formed by the merger of Corite Products, Inc., and Reynolds Corporation. Corite manufactures corrosion resistant plastic ducts, hoods, tanks and fans. Reynolds is a ventilating contracting and sheet metal fabricating firm.

Plastics

A catalog entitled "Plastic Stock Shapes, Molded and Fabricated Parts" has been issued by Garlock Inc., 455 Main St., Palmyra, N. Y. Included are units made from Teflon, Delrin, nylon and other resins.

•

Rubber coated access doors with fiberglass cores for industrial plants are being produced at the Butler, N. J., plant of American Hard Rubber Co., division of Amerace Corp. Called Ace Durador, the doors have the rubber jacket for protection against shock impact of fork-lift trucks. An all rubber hinge for corrosion and shock resistance extends the full length of the door.

•

Safety hats made of plastic resist corrosion, electrical shock and impact, according to the fabricator, Boyer-Campbell Co., 801 West Baltimore St., Detroit 2, Mich. The hat is designed to withstand impacts of 40 foot pounds without showing visible structural or material weakness.

•

Corrugated translucent vinyl sheet in continuous extrusions is being produced by National Rubber Machinery Co., Akron, Ohio. This sheet is designed to meet architectural requirements for structural glazing and internal partitioning. It offers design flexibility, structural strength and weather resistance, according to National Rubber.

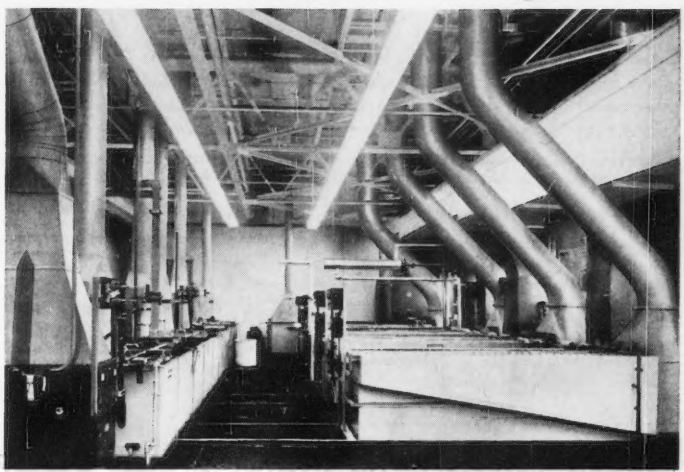
•

Corrosion from acidic process solutions in the manufacture of paper has been solved by use of unplasticized polyvinyl chloride pipe shrunk onto conveyor rolls. This plastic assembly on steel pipe was used in one plant to replace brass rolls that lasted only six months. Pipe

(Continued on Page 64)

HEIL of Cleveland

PLASTIC VENTILATING SYSTEM at *Western Electric* plant

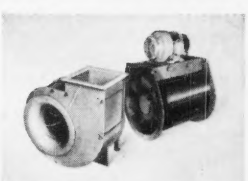


Heil Rigidon (Glass Reinforced Polyester) Exhaust System in the Plating Room of Western Electric Company's New Omaha Plant.

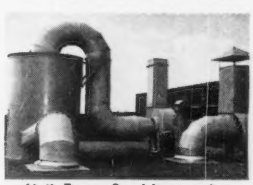
features attractive appearance, high strength, long life, easy installation and complete corrosion resistance

Western Electric Engineers wrote the specifications. The ventilating system for their plating room must look as modern and attractive as all other parts of their new plant. The system must positively resist exposure to fumes and the splash of acids and alkalies. It must be sturdy and rigid; and combine long life, low maintenance, be easy to install or re-arrange, and low in first cost. The Heil Rigidon system pictured above met all these requirements.

In your plant also, Heil service-proved plastic ventilating equipment will definitely cut the costs of handling corrosive fumes. Complete line, including collecting hoods, ducts, fans, stacks and fume scrubbers in Rigidon (reinforced plastic) or Rigivin (rigid vinyl) construction. Wide range of standard sizes speeds delivery and minimizes engineering costs.



Heil Centrifugal and Axial Rigidon Reinforced Plastic Fans.



Heil Fume Scrubber and Rigidon Duct Work.

Write today for Bulletin No. B-500. It lists chemical resistance data and specifications of standard sizes of equipment that can be installed by your own maintenance men or local contractor.

CHEMICAL-PROOF LININGS · TANKS HEATERS PLASTICS

HEIL PROCESS EQUIPMENT CORPORATION

12922 Elmwood Ave. • Cleveland 11, Ohio

NEW PRODUCTS

(Continued From Page 63)

for the rollers was furnished by A. M. Byers Company, Clark Bldg., Pittsburgh, Pa.

•

Fiberglass reinforced plastic marine antenna trunks are being fabricated for advantages of less weight, less maintenance and insulation characteristics gained over use of metals. The trunks can be fabricated in most any shape and are resistant to the marine atmosphere. They are made of Hetron, a corrosion resistant chlorinated polyester produced by Durex Plastics Division of Hooker Chemical Corp., Box 344, Niagara Falls, N. Y.

•

Neoprene adhesive is being used by automobile manufacturers as a "spot weld" between the inner and outer panels of auto hoods to prevent high speed flutter. The adhesive is automatically extruded on the outer panel at 45 points simultaneously. The inner panel is then mated to the hood and hem welded. The adhesive receives its complete cure when the hoods are painted and baked in ovens.

•

Tanks, piping, duct work, plastic coatings, cements and adhesives for chemical and petrochemical plants are being made by Armadillo Plastics, Inc., 2200 Welch, Houston, Texas. The firm also will do custom fabrication of polyester, epoxy and furan glass reinforced products.

•

Raschig rings for tower packings are being made of fluorocarbon resins by Resistoflex Corporation, Roseland, N. J., to provide product purity and to maintain uniform flow rates in mass transfer by resisting sludge build up. The rings are recommended for hydrofluoric and other acid processes at temperatures to 500 F.

•

Vertical or horizontal heavy duty glass reinforced polyester tanks for storing and processing corrosive liquids are being made by Justin Enterprises, Inc., 7000 Montgomery Pike, Cincinnati 36, Ohio. Available in capacities from 20 to 2,000 gallons, the tanks are made of a bisphenol-A polyester resin reinforced with glass fibers. The resin used is Atlac 382, manufactured by Atlas Powder Co., Wilmington, Del.

•

Gaskets made of polytetrafluoroethylene and perforated steel knit are being produced by Durco Modern Industrial Plastics Division, Box 1019, Dayton 1, Ohio, for resistance to acids, chemicals, solvents and other corrosive liquids. The steel knit is encased with the plastic to form a strong, resilient gasket designed to eliminate creep or cold flow.

•

Plastic insert Dall flow tubes made of fiberglass reinforced epoxy or polyester resins with metallic throat lining are being manufactured by B-I-F Industries, Inc., 345 Harris Ave., Providence 1, R. I. They are designed for primary flow metering where resistance to acids, alkalies, slurries and gases is required. They are available in sizes from 4 to 48 inches.

Welding

Pocket slide chart that gives pertinent resistance welding data is available from Ampco Metal, Inc., 1745 South 38th St., Milwaukee 46, Wis. The chart selects proper electrodes for joining many commonly welded ferrous and non-ferrous alloys. Correct top and bottom electrodes are indicated for over 160 combinations of alloys.

•

A new single specification covering items common to all specifications for covered welding electrodes has been issued by the Bureau of Ships, U. S. Navy Department. Entitled Military Specification Electrodes, Welding, Covered; General Specification, MIL-E-22200, the specification includes general requirements, quality assurance provisions, test procedures and instructions for preparation for delivery for covered welding electrodes.

POSITIONS WANTED AND AVAILABLE

Active and Junior NACE members and companies seeking salaried employees may run without charge two consecutive advertisements annually under this heading, not over 35 words set in 8 point type. Advertisements to other specifications will be charged for at $12.50 a column inch.

Positions Available

Corrosion Engineer—opportunity for salesman with large progressive manufacturer. Experienced man to handle advanced line of synthetic surface coatings. Man capable of building and eventually supervising complete group in area. Excellent salary, bonus and benefits. Reply in confidence. CORROSION, Box 60-30

WANTED
Manufacturers Agent

To sell complete line of corrosion proof materials—coatings, linings, cements, brick, and monolithic floor surfacings.

We require technically trained personnel presently selling to chemical and industrial plants in Alabama, Georgia, Florida or Mississippi. We can offer a protected territory.

Write giving background, size of organization and territory desired.

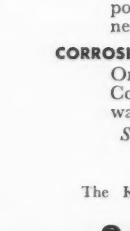
CORROSION, Box 60-31

Positions Available

CORROSION & MATERIALS ENGINEER

5 to 10 years' experience in Chemical industry. Prefer experience in corrosion, selection of materials of construction, pressure vessel design and welding. Must be Chemical or Mechanical Engineer with good background in Chemistry. Salary open. Send resume to—

SUNOLIN CHEMICAL CO.
1608 Walnut Street
Philadelphia 3, Pa.



ADVANCED NAVAL REACTOR DEVELOPMENT
at the
Knolls Atomic Power Laboratory

CHALLENGE AND OPPORTUNITY IN POSITIONS OF MAJOR RESPONSIBILITY

CORROSION ENGINEER

5 to 10 years experience. Evaluate materials for use in high temperature water, including measurement uniform corrosion, galvanic corrosion, stress corrosion, corrosion fatigue, and wear. Design and conduct or direct experiments. Prepare proposals, experimental design and reports. Work closely with metallurgists and design engineers.

CORROSION SCIENTIST

Originate, carry out and report results of programs on: Corrosion rates and mechanisms in high temperature water; Nature and transport of corrosion products.

Superior laboratory facilities. Publications encouraged.

Write to Mr. A. J. Scipione, Dept. 23-MK.
U.S. Citizenship Required

The Knolls Atomic Power Laboratory is operated for the A.E.C. by

GENERAL ELECTRIC

Schenectady, New York

MEN in the NEWS

Benjamin L. Page, chief of the length section of the National Bureau of Standards, has received a U. S. Department of Commerce Silver Medal for meritorious service in achieving high accuracy and reliability in inter-comparision and calibration of line standards of length.

•

Philip J. Parker has been appointed general sales manager of Sperry Products Company, Danbury, Conn.

•

A. C. Riddiford, lecturer in physical chemistry from the University of Southhampton, England, is scheduled to make a nation-wide lecture tour this fall. His trip is sponsored by American Gas & Chemicals Inc., P. O. Box 101, Gracie Station, New York 28, N.Y.

•

George J. Scheuer has been named to the new created position of plastics division manager for Chemo Products, Inc., West Warwick, R. I.

•

Noel M. Thomas has joined the plastics and synthetics division of U. S. Stoneware Company, Akron 9, Ohio.

•

Frank H. Vandenburgh has joined Oregon Metallurgical Corp., Albany, Ore., as vice president and sales manager.

•

M. M. Rand has been appointed to the newly created position of manager of carbon electrodes and refractories for National Carbon Company, Division of Union Carbide Corp., 100 E. 42nd St., New York 17, N.Y. **Floyd M. Hunsaker** has joined National Carbon's technical service department as a specialist on spectroscopic carbon and graphite products.

•

New corporate officers named for Tube-Kote, Inc., P. O. Box 20037, Houston 25, Texas, are as follows: **E. G. Holm,** president; **J. L. McConn,** vice president and assistant treasurer; **R. S. Martin,** vice president of operations; **L. C. Edgar,** vice president and technical manager; and **I. C. May,** treasurer and assistant secretary.

•

Edward O. Hilbush, Jr., has assumed the duties of president of West Chester Chemical Co., P. O. Box 39, West Chester, Pa.

•

Dale Miller, formerly with Pure Oil Company, has been appointed product engineer for Tubular Lining Corp., P. O. Box 20015, Houston 25, Texas.

•

Harry K. Brill has been named general sales manager for A. O. Smith Corporation's Atomic and Process Equipment Division, Milwaukee, Wis.

•

Eldon L. Hall has been appointed technical supervisor of the Plastics Department at American Viscose Corporation's plant at Fredericksburg, Va.

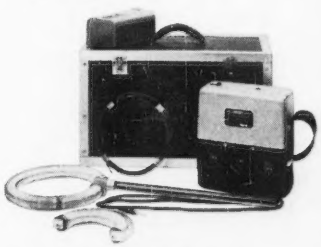
•

E. G. Holm, Jr., an NACE member, was elected to board of directors of Tuboscope Company, 2919 Holmes Rd., Houston, Texas. He also is president of Tube-Kote, Inc., a subsidiary of Tuboscope.

(Continued on Page 66)

FOUR WAYS TO INSURE GOOD COATING PROTECTION

Continuity is all important in a protective coating. Whether it's a 90 mil coating on a pipeline or a 3 mil coating on a chemical tank, a tiny pinhole can lead to the destruction of the coating. Use of a Tinker and Rasor Holiday Detector will quickly locate pinholes as well as weak spots caused by air bubbles, coke, rust or scale. Minutes spent inspecting with a Tinker and Rasor Holiday Detector while the job is open can save days of down time later on.



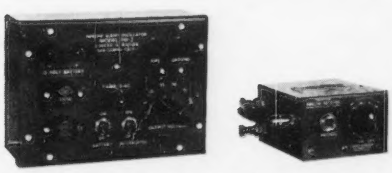
Pipeline Detectors

E-P For damp or dry surface, high electrical resistance coatings. Output adjustable from 8000 to 20,000 pulsating voltage. Electrodes available: half circle, spring for pipe to 6", full circle to 30" silicone brush for flat surfaces.

E-4 This lower cost type of detector is specifically designed for smaller diameter pipe and flat surfaces with dry surface, high electrical resistance coatings. Output adjustable from 8000 to 20,000 D.C. voltage.

Thin Film Detector

M-1 For painted or sprayed thin film coatings. Maximum applied voltage 67½ V., non-destructive to coatings. Belt mounted, 4 lbs. total wt.



Underground Pipeline Detector

P-D For detecting holidays, electrical contacts or locating the pipeline itself, **without uncovering the pipeline.** Completely transistorized—long life and light weight.

Engineering Note:

Every protective coating specification should include TR Holiday Detector inspection. Write for specification guide.

DISTRIBUTORS:

Falcon Line Products Corp., Kearny, New Jersey
Crutcher-Rolfs-Cummings, Inc., Houston, Texas
Remco Manufacturing Co. Inc., Tulsa, Oklahoma
Bob Herrick, New Cumberland, Pennsylvania
Canadian Equipment Sales & Service Co. Ltd., Edmonton, Alberta, Canada

Export Agent: Frazar & Hansen Ltd., San Francisco, Calif.

Write today for technical data and bulletin.

Quality Control for Coating Application

TR TINKER & RASOR

417 Agostino Road, P.O. Box 281 • San Gabriel, California

MEN in the NEWS

(Continued From Page 65)

Jack D. Rice, recently appointed director of procurement for Koppers Company, Inc., Pittsburgh 19, Pa., has been elected a vice president.

•

Philip T. Rogers has been appointed vice president and general manager of the Arco-Wynn Valve Division of Automotive Rubber Co., 12550 Beech Rd., Detroit 39, Mich.

•

NACE member **Walter T. Singleton, Jr.,** in charge of sales management for Wisconsin Protective Coating Corp., Green Bay, Wis., is making a business trip through Europe and the Middle East for sales development work with export representatives.

•

Alvin S. Baer has joined Truscon Laboratories, Detroit 11, Mich., as vice president. Truscon has opened an eastern district sales office at 79 Madison Ave., New York, N.Y.

•

Howard O. Beaver has been appointed assistant general superintendent of Carpenter Steel Company's plant in Reading, Pa.

•

Jacob I. Bregman, an NACE member, presented a technical paper recently at the European Symposium on Corrosion Inhibitors at the University of Ferrara, Italy.

•

Joseph W. Brown has been appointed field sales representative for Geigy Industrial Chemicals, Division of Geigy Chemical Corp., Saw Mill River Rd., Ardsley, N.Y. He will have headquarters in Los Angeles, Cal.

•

John K. Bybee will represent Ampco Metal, Inc., in the southeastern United States with headquarters at 3469 Spring Circle, Decatur, Ga.

William A. Cooper has been appointed to the new post of manager of distributor sales for Goodyear Tire & Rubber Company's Industrial Products Division, Akron, Ohio.

•

Mack E. Dominy will supervise plant production at Tube-Kote's new plant at Edmonton, Alberta, Canada.

•

Norman G. Duke has been named manager of the product application laboratory at B. F. Goodrich Chemical Company's plant at Avon Lake, Ohio.

•

Donald F. Fraser, vice president of manufacturing for Garlock Inc., Palmyra, N.Y., died of a heart attack September 12.

•

Two additions to the staff of U. S. Stoneware Company's Chamberlain Laboratories at Akron, Ohio, are **Richard H. Freyer** as manager of the testing laboratory and **Alan Corry** as research engineer.

CORROSION ENGINEERING DIRECTORY

WAYNE BROYLES ENGINEERING CORP.
CATHODIC PROTECTION
Installation
DESIGN SURVEYS
P.O. Box 1169 • FAirfax 3-6858 • Houston 1, Texas

Electro Rust-Proofing Corp.
Engineering Division
ERP
Corrosion Surveys
Cathodic Protection Design
Plans • Specifications
Electrolysis Control
Testing
BELLEVILLE 9, NEW JERSEY
Atlanta • Chicago • Dallas • Monrovia

FRANCIS W. RINGER ASSOCIATES
• *Consulting Corrosion Engineers*
7 Hampden Ave. MOhawk 4-2863
NARBERTH (Suburb Phila.) PENN.

cathodic protection service
CPS
Twenty cathodic protection engineers with a combined total of over 150 years experience available to serve you with ABILITY and INTEGRITY.
Houston 4601 Stanford St.
Branch Offices: Chicago • Corpus Christi
New Orleans • Odessa • Tulsa

CATHODIC PROTECTION
• ENGINEERING
• SURVEYS • CONSTRUCTION
Systems for conventional and specialized applications
THE HARCO CORPORATION
4592 East 71st St. VUlcan 3-8787
Cleveland 25, Ohio

A. V. SMITH ENGINEERING CO.
CONSULTING ENGINEERS
Essex Bldg. Narberth, Pa.
119 Ann Street Hartford 3, Conn.

CATHODIC PROTECTION by Coreco
SURVEYS • DESIGNS
INSTALLATIONS
CORROSION RECTIFYING CO., INC.
5310 ASHBROOK • MO 7-6659
HOUSTON 36, TEXAS

THE HINCHMAN CORPORATION
Consulting Engineers
"WORLD-WIDE ACTIVITIES"
Survey • Design • Supervision
Specializing In
Corrosion Control • F.C.C. Certification Tests
Electromagnetic Interference Studies
Francis Palms Bldg. Detroit, Mich.

SOUTH FLORIDA TEST SERVICE
INCORPORATED
Testing—Inspection—Research—Engineers
Consultants and specialists in corrosion, weathering and sunlight testing.
4301 N.W. 7th St. • Miami 44, Florida

CORROSION SERVICE LIMITED
CSL offers in CANADA
A Complete Service in Corrosion Engineering
Design and installation of cathodic protection systems. Supervision. Resistivity and electrolysis surveys. Selection and application of protective coatings.
17 DUNDONALD ST., TORONTO 5

ICCC Interprovincial Corrosion Control Company Limited
5325 Third St. S.E. Calgary, Alberta
CANADA
P. O. Box 310 Burlington, Ont.
CONSULTING ENGINEERS
Survey Design — Materials and Equipment — Installations

WATER SERVICE LABORATORIES, INC.
CORROSION PREVENTION
Specialists in Water Treatment
Main Office, 615 West 131st St., N. Y. 27, N. Y.
Offices Also in Philadelphia, Washington and Richmond, Va.

CORROSION ENGINEERING
EBASCO SERVICES
INCORPORATED
TWO RECTOR STREET, NEW YORK 6, N. Y.
CHICAGO • DALLAS • PORTLAND, ORE.
SAN FRANCISCO • WASHINGTON, D. C.

"PUTTING PERMANENCE IN PIPE"
For Over 30 Years
MAYES BROTHERS, INC.
1150 McCarty Phone: OR 2-7566
HOUSTON, TEXAS

Reach more than 8000 paid readers monthly in this directory at a cost of about $1.50 per thousand. Ask for rates.

Plans Being Completed for Buffalo Conference

Technical Program To Include Nineteen Symposia, Lectures

Technical papers are being scheduled for 16 symposia on a variety of corrosion problems for presentation at the 17th Annual NACE Conference, March 13-17, 1961, at the Hotel Statler-Hilton, Buffalo, N.Y.

The technical program also will include a series of three educational lectures and two round table discussions of pipeline, underground and general corrosion problems. A special feature of the program will be a session titled "What NACE Can Do for You" in which representatives from several industries will discuss advantages and benefits which their industry or company has derived from NACE.

The 1961 Buffalo Conference will be the first NACE has held in the heavily industrialized Northeast since the 1956 meeting in New York City. The 1961 Corrosion Show will be held in conjunction with the March 13-17 meeting. (See accompanying story.)

Chairmen and co-chairmen of the technical symposia are given below. (Photographs of these men appear on Page 68.)

Cathodic Protection: Sidney Tudor, New York Naval Shipyard, Brooklyn, Herman S. Preiser, Navy Department, Washington, D.C.

Chemical Industries: Otto H. Fenner, Monsanto Chemical Co., St. Louis, Mo., Charles W. Ambler, American Zinc, Lead & Smelting Co., East St. Louis, Ill.

Missile Industry: Edison H. Phelps, U. S. Steel Corp., Monroeville, Pa.

Inhibitors: Arthur J. Freedman, Nalco Corp., Chicago, Ill., Robert Legault, General Motors Technical Center, Warren, Mich.

Corrosion Principles: C. P. Dillon, Union Carbide Chemicals Co., Charleston, W. Va., W. K. Boyd, Battelle Memorial Institute, Columbus, Ohio.

Elevated Temperatures: David Roller, Magna Products, Inc., Santa Fe Springs, Cal., Anton de S. Brasunas, American Society for Metals, Novelty, Ohio.

General Corrosion: Jerome M. Bialosky, Koppers Co., Inc., Verona, Pa., Franklin H. Beck, Ohio State University, Columbus, Ohio.

High Purity Water: W. K. Boyd, Battelle Memorial Institute, Columbus, Ohio, A. L. Meddin, U. S. Steel Corp., Monroeville, Pa.

Marine: W. L. Miller, New York Naval Shipyard, Brooklyn, N. Y., F. W. Fink, Battelle Memorial Institute, Columbus, Ohio.

Oil and Gas Production: W. C. Koger, Cities Service Oil Co., Bartlesville, Okla., J. A. Caldwell, Humble Oil & Refining Co., Houston, Texas.

Pipe Line—General: Carleton L. Goodwin, Portland Pipeline Corp., Portland, Maine, E. L. Karraker, Shell Oil Co., Indianapolis, Ind.

Plastics: John Delmonte, Furane Plastics, Inc., Los Angeles, Cal., Raymond B. Seymour, Sul Ross College, Alpine, Texas.

Protective Coatings: Newell D. Casdorph, Union Carbide Chemicals Co., Port Lavaca, Texas, J. P. Ferraro, American Cyanamid Co., Bound Brook, N. J.

Pulp and Paper Industry: F. J. Ploederl, Wisconsin Protective Coating Co., Green Bay, Wis., R. R. Pierce, Pennsalt Chemical Co., Natrona, Pa.

Refining Industry: F. B. Hamel, Standard Oil Co., Cleveland, Ohio, G. C. Hall, Richfield Oil Corp., Wilmington, Cal.

Utility Industries: A. W. MacKay, Detroit Edison Co., Detroit, Mich., Carl M. Thorn, Southwestern Bell Telephone Co., San Antonio, Texas.

Chairman and co-chairman for the Educational Lectures will be Norman D. Groves, Carpenter Steel Co., Reading, Pa., and J. James Hur, Atlantic Refining Co., Philadelphia, Pa.

Round table discussion chairmen will be P. C. Hoy of Dayton Power and Light Co., Dayton, Ohio, and L. W. West of Standard Oil Co., Fostoria, Ohio, for the discussion on pipeline and underground corrosion and John J. Halbig, Sr., of Armco Steel Corp, Middletown, Ohio, and B. P. Gladis of International Nickel Co., Inc., New York, N.Y., for the discussion on general corrosion problems.

L. W. Gleekman of Wyandotte Chemical Co., Wyandotte, Mich., will be chairman of the session on "What NACE Can Do for You."

•

NACE Certificates of Membership are available from the Central Office. Measuring 5½ x 8½ inches, the certificates cost $2 each and are signed by the association president and executive secretary.

•

NACE's Bibliographic Surveys of Corrosion extend from 1945 to 1955. Prices available upon request.

Ninety Percent of Booth Space Sold For Corrosion Show

Twelve more companies have requested booth space for the 1961 Corrosion Show. A total of about 90 percent of the available exhibition space has been requested to date.

The 1961 Corrosion Show will be held in conjunction with the 17th Annual NACE Conference, March 13-17, at the Hotel Statler-Hilton, Buffalo, N.Y.

Booths will be located on the same floor of the hotel as most of the technical meetings so that registrants can visit the exhibition during free times. No technical symposia meetings are scheduled for the afternoon of March 14, opening day of the Corrosion Show.

Twelve New Exhibitors

The twelve companies requesting booth space since the complete list of exhibitors was published on Page 55 of the October issue of **Corrosion** are as follows:

Cathodic Protection Service, Central Plastics, Coast Paint & Lacquer Co., Dearborn Chemical Co., John L. Dore Co., Duriron, du Verrl, Inc., Metallizing Service Contractors, Owens Corning, H. C. Price Co., Radio Receptor, Seamless Rubber and Tinker & Rasor.

Show Brochures Available

Companies interested in making arrangements for exhibit space at the 1961 Corrosion Show should contact R. W. Huff, Jr., NACE Central Office, 1061 M & M Bldg., Houston 2, Texas. Copies of the Corrosion Show Brochure will be sent, giving complete details on booth sizes, facilities and location in the hotel exhibit area.

Color Slide to be Made

Color slides will be made of products on exhibit at the Corrosion Show for a slide-talk presentation which will be available for use by NACE section meetings and by other interested groups.

Section program chairmen should contact Gilbert Rolak to make booking arrangements for the 1961 Corrosion Show slide-talk, which will be abailable about April 15.

See Pages 70, 74 and 75 for stories and photographs on the Western Region Conference held in San Francisco, Southeast Region Conference in Atlanta, Ga., Northeast Region Conference in Huntington, W. Va., and the San Joaquin Valley Corrosion Tour held in Bakersfield, Cal.

Chairmen for 1961 Buffalo Conference Program

Bialosky

Casdorph

Gleekman

Goodwin

Koger

MacKay

Delmonte

Dillon

Groves

Halbig

Miller

Phelps

Fenner

Freedman

Hamel

Hoy

Ploederl

Roller

First Time Available in U.S.!

TESTED, PROVEN—

NEW HIGH (To 1500 C) TEMPERATURE CORROSION RESISTANT COATING

Oxide-resistant, oil-resistant and salt water-resistant

Send for Specifications, Laboratory Report

JAPANESE COMMERCIAL CONSULTING SERVICE
Suite 1417, 360 N. Michigan, Chicago 1, Ill.

Tudor

British Institute to Hold Nov. 30-Dec.1 Symposium

A symposium on steels for reactor pressure circuits will be held in London November 30-December 2 under the sponsorship of the Iron and Steel Institute. Twenty papers on recent research in Canada, Great Britain and the United States will be presented. These will cover high temperature properties, corrosion, fabrication, irradiation effects and steels for future reactors.

•

News deadline for CORROSION is the 10th of each month.

South Central Region

Houston Section to Hold Feb. 2-3 Short Course

Plans are being made for the 7th Annual Houston Section Corrosion Control Short Course to be held February 2-3 at the Rice Hotel, Houston.

J. A. Caldwell of Humble Oil & Refining Company is general chairman of the short course planning committee. Ben Russell of Rio Engineering Company has been appointed treasurer and registrar. Other committee appointments include T. M. Heitman of United Gas Corporation for arrangements and Rudy Zorn of Cameron Iron Works Inc., for publicity.

Recognized authorities will be scheduled for lectures on corrosion and methods of control in transmission pipeline operations, oil and gas production, refineries and chemical plants, utilities and commercial and residential construction.

A record enrollment of about 300 was counted at the section's short course held last January.

NACE Member Hackerman Assigned New Position

NACE Member Norman Hackerman of the University of Texas has been given the newly created post of Dean of Research and Sponsored Programs. He will be in charge of government and private research grants and will continue in his present position as chairman of the Chemistry Department.

•

New Orleans Section scheduled a talk on cathodic protection of well casings by Wayne Johnson of Corrosion Rectifying Co., Houston, Texas, for its October 17 meeting.

•

North Texas Section heard A. E. Erben of Sun Oil Company speak on cathodic protection studies in the laboratory and in the field at the October 10 meeting.

•

Sabine-Neches Section heard Don C. Smith of Gulf Oil speak at the September 29 meeting on corrosion engineering in Iran, where he has been working for three years.

•

Shreveport Section had Philip P. Corneli of Tretolite Co., Baton Rouge, La., speak on plant corrosion problems at the October 4 meeting.

•

Panhandle Section members saw slides showing corrosion problems in a chemical plant making ammonia, nitric acid and amonium nitrate for the September 27 meeting. Discussion leader was J. H. Long of Phillips Chemical Company.

•

East Texas Section heard Dorsey Fincher of Houston speak on inhibitors and their application at the September 27 meeting.

•

Rocky Mountain Section saw color films on the application of plasticized coal tar linings for 13-foot diameter penstocks and tunnel liners at the September 16 meeting. The films were shown by Kim Ellis of Hill Hubbell.

•

Greater Baton Rouge Area Section has scheduled Burke Douglas of Dow Metal Products to speak on corrosion control products for the November 21 meeting.

The December meeting date is to be set, but the program will be on applications of stainless steel in industry.

Joseph E. Rench, Napko, Corp., Houston, gave a slide-talk on paint application and surface preparation at the October 17 meeting.

•

Lapel pins approximately 7/16 inches high, made of gold with inlaid red enamel and a ruby center, are available to NACE members only. Price is $10. Address orders to Executive Secretary, 1061 M & M Bldg., Houston 2, Texas.

Trade Missions Program

The National Association of Corrosion Engineers is among the 600 members of the American business press participating in the Trade Missions Program sponsored by the U. S. Department of Commerce. These 600 members contribute the 1000-unit library which accompanies each Trade Mission into foreign countries to desseminate information about the American capitalistic system.

Twelve Trade Missions have been planned in the following countries for 1960-61: Afghanistan, Iran, France, East Africa, Ceylon, Colombia, the Southern Caribbean area, Australia, Japan, Germany, Chile, Uruguay, West Africa and Nigeria.

60 OIL WELLS PROTECTED FROM CASING CORROSION

A major company operates 60 oil wells in a field in Coke County, West Texas. When external casing corrosion became a problem, it was decided to protect 35 of the wells cathodically. CSI was given engineering and turn-key installation contracts on a competitive bid basis.

CSI determined the current required for protection on each well, using the "log current potential method" developed and *patented* by a CSI engineer. Current requirements were verified by a down-the-hole potential drop profile. Then CSI installed rectifiers to supply the current.

Recently CSI was recalled—again on a competitive basis—to protect the other 25 wells. CSI again installed rectifiers. CSI also submitted a report covering all installation data, and instructed company personnel on the operating of the rectifiers.

You can benefit from the expert engineering and installation services offered by CSI engineers—who helped pioneer cathodic protection for pipe lines, well casing, tank bottoms, etc. CSI also offers quality supplies for both rectifier and magnesium anode installations. Call or write today.

CSI

Cleveland 13, Ohio
1309 Washington Ave.
Tel. CHerry 1-7795

CORROSION SERVICES INCORPORATED
General Office: Tulsa, Okla.
Mailing Address:
Box 787, Sand Springs, Okla.
Tel. Circle 5-1351

Southeast Region

RECORD ATTENDANCE of 118 was registered for the October 6-8 Southeast Region Conference in Atlanta, Ga. Registrants stated the conference was one of the most successful held by the region. Shown above at left are two of the speakers (left to right) Keith Kelley of Cape Canaveral, Fla., and C. P. Larrabee of U. S. Steel, discussing missile corrosion problems with H. T. Rudolf of Atlantic Coatings Co., Jacksonville, Fla., who was general program chairman for the meeting. Shown at the right is an informal group at the fellowship hour. They are left to right Fred Lubke of Atlantic Coatings Co., Jacksonville, Mrs. Lubke, John Millican of Buckeye Cellulose, Foley, Fla., Mrs. John Weeks, Mrs. John Millican and Mrs. H. T. Rudolf, standing.

Ohio Valley Section has planned a program on high temperature corrosion for its December 6 meeting to be held jointly with the American Society for Metals at the White Cottage, Louisville, Ky. Guest speaker will be E. L. Simons of General Electric Research Laboratory, Schenectady, N.Y.

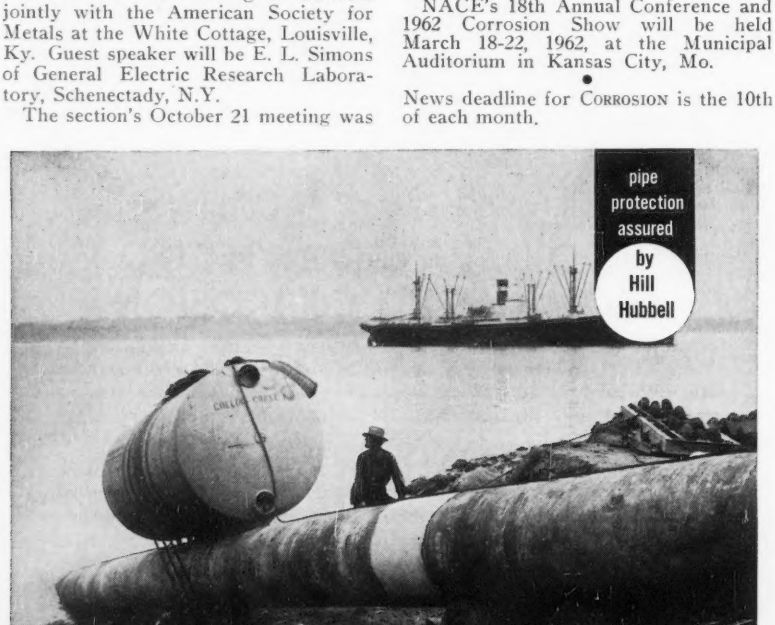
The section's October 21 meeting was held jointly with the Louisville Electrolysis Committee.

•

NACE's 18th Annual Conference and 1962 Corrosion Show will be held March 18-22, 1962, at the Municipal Auditorium in Kansas City, Mo.

•

News deadline for CORROSION is the 10th of each month.



vital narrows crossing *fully protected*

This underwater pipeline across New York Harbor "Narrows" will serve Brooklynites for many years, thanks to optimum corrosion protection applied by Hill Hubbell.*

Underwater or underground, long, trouble-free service is assured if you specify Hill Hubbell — the name synonymous with quality in mill coated-and-wrapped pipe.

*Pipe in photo weighted with concrete covering over Hill Hubbell protection.

Specify Hill Hubbell wrapped pipe on your next job . . .

HILL HUBBELL

3091 MAYFIELD RD. • CLEVELAND 18, OHIO • YELLOWSTONE 2-7535

Few Replies Received on Binders for "Corrosion"

Only 15 readers of CORROSION expressed an interest in buying a binder in which copies of CORROSION could be kept. The deadline for replies was October 1 This is far too few to justify stocking and selling the binders by NACE. Original estimates of minimum interest contemplated favorable response from not less than 100 readers. The order of interest in binders is about what was indicated several years ago when a similar project was considered.

The offer concerning the binders was made in an advertisement and a news story on Page 55 of the August issue and in an advertisement on Page 42 of the September issue. The advertisement also was published on Page 62 of the October issue.

J. Frank Putnam Reads His Own Obituary

J. Frank Putnam, a former NACE member, has due cause to quote Mark Twain, who cabled the Associated Press in 1897: "The reports of my death are greatly exaggerated." Twain had seen a published report of his death in the newspaper while he was in London.

On Page 55 of the October issue of CORROSION, Mr. Putnam saw a report of his death. NACE Central Office has received letters and phone calls from persons attending the NACE Southeast Region Conference in Atlanta, Ga., telling that Mr. Putnam was there in person, alive.

Basis for the published item on the death of Mr. Putnam was a report from California that Joseph F. Putnam had died August 23. The only record on file was a former member by the name of J. Frank Putnam.

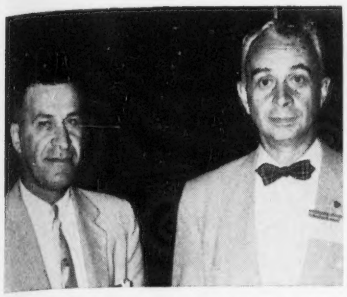
Mr. Putnam now is president of Utility Services, Inc., 277 Mayson Ave., N.E., Atlanta 7, Ga.

1960 Corrosion Show Color Slide-Talk

A show consisting of 108 color slides has been prepared showing some of the exhibits at the March 15-17 Dallas exhibition. This 1960 Corrosion Show color slide presentation will be accompanied by a commentary describing the exhibits and many of the items displayed.

NACE Section program chairmen who are interested in using this in one of their programs may make bookings by writing to G. A. Rolak, 1061 M & M Bldg., Houston 2 Texas.

The show gives members who were unable to attend the conference an opportunity to see some of the exhibits at what many have said was the best Corrosion Show held so far.



REPRESENTING SPONSORS of the short course on process industry corrosion are Mars G. Fontana (left), chairman of the Ohio State University Department of Metallurgical Engineering, and W. H. Burton of Allied Chemical Corp., Camden, N.J., who is vice chairman of NACE Technical Committee T-5.

Ohio State University Short Course Has Registration of 119

Total registration at the short course on process industry corrosion held September 12-16 on the Ohio State University campus was 119. The course was presented by the University's Department of Metallurgical Engineering of the College of Engineering in cooperation with NACE's Technical Group Committee T-5 on Corrosion Problems in the Process Industries.

Proceedings of the short course including all papers presented are being printed and will be mailed to all registrants.

Additional copies of the proceedings will be available. Information on these can be obtained from NACE Central Office, 1061 M & M Bldg., Houston 2, Texas.

Shown in the accompanying photograph are Mars G. Fontana of Ohio State Universilty and T-5 Vice Chairman W. H. Burton of Allied Chemical Corporation.

TECHNICAL REPORTS

on

MARINE COATINGS

T-1M Suggested Coating Specifications for Hot Application of Coal Tar Enamel for Marine Environment. A Report of NACE Technical Unit Committee T-1M on Corrosion of Oil & Gas Well Producing Equipment in Offshore Installations. Publication No. 57-8. Per Copy $1.50

T-1M Suggested Painting Specifications for Marine Coatings. A Report of NACE Technical Unit Commirtee T-1M on Corrosion of Oil & Gas Well Producing Equipment in Offshore Installations. Publication No. 57-7. Per Copy $1.50.

Remittance must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 85c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

1061 M & M Bldg. Houston 2, Texas

North Central Region

Pascoe Given Cook Award At Detroit Section Meeting

Edwin A. Pascoe, a 1960 graduate of Wayne State University, was presented the annual L. David Cook, Jr., Memorial Award for outstanding undergraduate work in chemical engineering related to the field of corrosion. The award was presented by Mrs. Cook and H. G. Donnelly, chairman of the Chemical Engineering Department at Wayne State.

The award was given at the Detroit Section's Annual Cook Memorial Meeting.

Mr. Pascoe's thesis was on corrosion of titanium in hydrochloric acid in the presence of chlorine and air.

The award, consisting of a certificate, fifty dollars, a one-year membership in NACE and a copy of the Corrosion Handbook, is given annually as a memorial to the late L. David Cook, Jr., one of the founders of the Detroit Section.

•

Twin City Section heard J. F. Wilkes of Dearborn Chemical Company speak on the cause and control of corrosion in water systems at the October 11 meeting.

•

Detroit Section planned a tour through the International Salt Mine for its October 20 meeting.

•

Certificates for past chairmen of regions and sections, measuring 9 x 12 inches, are available from the Central Office at $7.50 each.

Free booklet shows how TRANSITE® PIPE CUTS COSTS in storm water drainage & storm sewer systems

Send for your copy today!

JOHNS-MANVILLE Box 14, CO-11. New York 16, N. Y.

Please send me, without obligation, your facts and data booklet on Transite Pipe Storm Water Drainage and Storm Sewer Systems.

NAME_____

ADDRESS_____ CITY_____

ZONE_____ COUNTY_____ STATE_____

"They engineered this oil line to a cat's whisker"—then wrapped it with Polyken tape

One of the world's largest pipeline operators chooses the world's toughest tape coating for new Patagonian oil line

A leading international pipeline company recently wrapped over 100 miles of crude oil gathering and transmission line with Polyken No. 960 Extra-Strength Pipeline Roll.

The new line, which crosses part of the Patagonian plateau of southern Argentina, is an example of perfection in pipeline design. "They engineered it to a cat's whisker," is the way a seasoned pipeliner put it.

In their construction plans, the engineers specifically called for Polyken No. 960 Tape. Seven years of testing and study had convinced these people that Polyken delivers the durable, practical protection that a precision-built line needs.

There's a lot more to be said for Polyken tape. See your Polyken representative, or call the Polyken tape coating distributor nearest you. Or simply write Polyken, 309 West Jackson Blvd., Chicago 6, Ill.

Using tensioned-spindle equipment, pipe is cleaned and wrapped in one factory-smooth operation. Polyken tape is ready. No primer, no drying or cooling. No fumes or fire hazard.

THE MODERN WAY

Polyken®

EXPERIENCED IN PROTECTIVE COATINGS

THE KENDALL COMPANY
Polyken Sales Division

POLYKEN
PROTECTIVE
COATINGS
DISTRIBUTORS

Atlanta, Georgia
Steele & Associates, Inc.

Chicago, Illinois
Sales Engineering, Inc.

Cincinnati, Ohio
Hare Equipment

Cleveland, Ohio
The Harco Corp.

Denver, Colorado
Patterson Supply Co.

Fort Worth, Texas
Plastic Engineering & Sales Corp.

Houston, Texas
Cathodic Protection Service

Jackson, Michigan
Utility & Industrial Supply Co.

Kansas City, Missouri
H. J. Hodes Co.

Kansas City, Missouri
Industrial Coating's Engineering Co.

Long Beach, Calif.
Barnes & De'aney

Memphis, Tenn.
General Pipe & Supply Co.

Minneapolis, Minn.
Simcoe Equipment Co.

New Orleans, Louisiana
L. F. Gaubert & Co.

Philadelphia, Pa.
Harold N. Davis Co.

Plainfield, New Jersey
Stuart Steel Protection Corp.

San Francisco, Calif.
Incandescent Supply Co.

San Francisco, Calif.
Phillips & Edwards Electric Co.

Seattle, Washington
Farwest Corrosion Control Corp.

Seattle, Washington
Pacific Water Works Supply Co.

St. Louis, Missouri
Shutt Process Equipment Co.

Tulsa, Oklahoma
Midwestern Pipe Line Products Co.

Polyken
Experienced in modern PROTECTIVE COATINGS

Canadian Region

Paper Added to Nov. 14-15 Eastern Division Program

Another paper has been added to the final program for the Eastern Division Conference of the Canadian Region to be held November 14-15 at the Hotel Royal in Montreal, Quebec. This change given below is made on the tentative program published on Page 68 of the September issue of CORROSION and the final program given on Page 64 of the October issue.

The new paper is "Some Corrosion Tests and Control Methods Used on Underground Structures" by E. R. Perkings of the North East Telephone and Telegraph Company.

•

Vancouver Section will hear Duncan Fraser of Standard Oil of British Columbia speak on high chrome as a material for mechanical wearing parts at the November 17 meeting.

For the December 15 meeting, a slide-talk presentation on the 1960 NACE Dallas Conference will be given. The October meeting was on industrial plastics.

•

Toronto Section heard H. A. Webster of Corrosion Service Ltd., speak on de-icing salts and their effect on buried structures and autos at the October 13 meeting.

•

Edmonton Section had a panel discussion for its September 22 meeting with 39 guests and members attending.

•

Montreal Section had 25 guests and members at its September 13 meeting. Two color films were shown: "Wrapping a West Texas Gas Line with Polyken Tape" and "Zinc Controls Corrosion."

Appalachian Short Course Committee Chairmen to Meet

A meeting of the committee chairmen of the Appalachian Underground Corrosion Short Course will be held December 1 at the Penn-Sheraton Hotel, Pittsburgh, Pa., to make plans for the Sixth Annual Short Course. Dates for the short course have been set for June 6-8, 1961, at the University of West Virginia, Morgantown, W. Va.

The committee chairmen will hold a luncheon meeting and an afternoon meeting.

Some of the chairmen will participate that evening in a round table discussion at the Pittsburgh Section meeting also at the Penn-Sheraton Hotel. Moderator of the discussion will be C. A. Erickson, chief corrosion engineer with Peoples Natural Gas Co., Pittsburgh.

Short committee chairmen are as follows: General Chairman D. A. Tefankjian of Texas Eastern Transmission Co., Shreveport, La., Program Committee Chairman E. K. Benson of New York Telephone Co., Buffalo, N. Y., Registration Chairman R. E. Hanna, Jr., of West Virginia University, Exhibits Committee Chairman G. G. Campbell of West Virginia University, and Publicity Committee Chairman John H. Alm of Dearborn Chemical Co., Pittsburgh, Pa.

A record of 600 persons attended the Fifth Annual Appalachian Underground Corrosion Short Course held last June. The course is sponsored by the University of West Virginia and is endorsed by NACE and the American Water Works Association.

NATIONAL and REGIONAL MEETINGS and SHORT COURSES

1960

November 14-16—Eastern Division, Canadian Region Conference, Hotel Royal, Montreal.

November 17-18—NACE Board of Directors Meeting, Sherman Hotel, Chicago, Ill.

1961

March 12—NACE Board of Director's Meeting, Hotel Statler, Buffalo, N. Y.

March 13-17—17th Annual Conference and 1961 Corrosion Show, Buffalo, N. Y., Hotel Statler.

March 17—NACE Board of Director's Meeting, Hotel Statler, Buffalo, N. Y.

Oct. 4-6—Western Region Conference, Hotel Multnomah, Portland, Oregon.

Oct. 9-11—North Central Region Conference, St. Louis, Chase Park Plaza Hotel.

Oct. 24-27—South Central Region Conference and Exhibition, Shamrock-Hilton Hotel, Houston.

Oct. 30-Nov. 2—Northeast Region Conference, New York City, Hotel Statler.

Southeast Region Conference, Miami, Fla., in conjunction with Miami Section's short course.

1962

March 19-23—18th Annual Conference and 1962 Corrosion Show. Kansas City, Municipal Auditorium.

October 1-4—Northeast Region Conference, Hotel Sheraton Ten Eyck, Albany, N. Y.

October 9-11—North Central Region Conference.

October 11-12—Southeast Region Conference, Birmingham, Ala.

October 16-19—South Central Region Conference and Exhibition, Granada Hotel, San Antonio.

SHORT COURSES

1960

November 7-11—Annual Florida General Conference Corrosion Short Course, Key Biscayne Hotel, Miami. Sponsored by Miami and Jacksonville Sections.

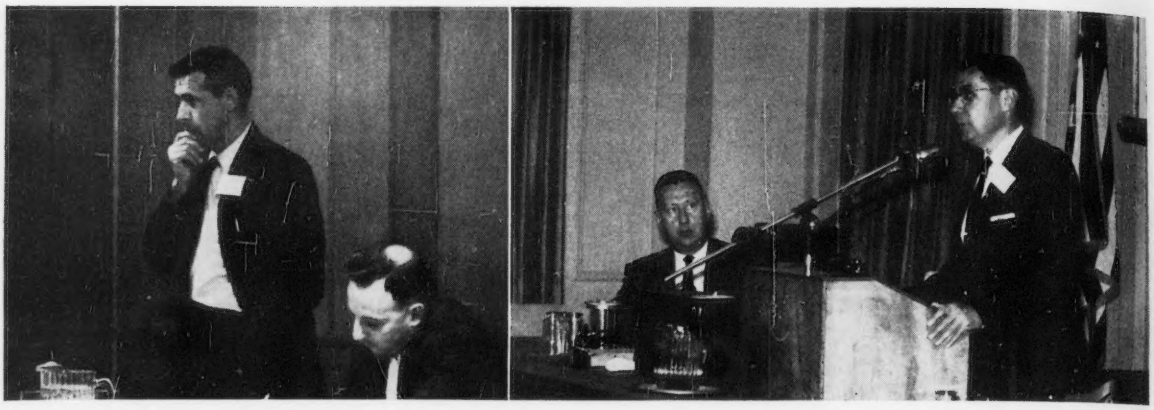
1961

February 2-3—7th Annual Houston Section Corrosion Control Short Course, Rice Hotel, Houston, Texas.

June 6-8—6th Annual Appalachian Underground Corrosion Short Course, University of West Virginia, Morgantown.

•

Lapel pins approximately 7/16 inches high, made of gold with inlaid red enamel and a ruby center, are available to NACE members only. Price is $10. Address orders to Executive Secretary, 1061 M & M Bldg., Houston 2, Texas.



EDGAR V. KUNKEL, CELANESE CORP., Bishop, Texas (standing, left) presides at a meeting of Technical Committee 6F during the Northeast Region meeting at Huntington. Seated at his left is L. W. Gleekman, Wyandotte Chemicals Corp., Wyandotte, Mich. (Right) R. G. Fortener, Jones Dabney Co., Louisville, Ky. presents the opening paper at the Protective Coatings for Immersion Service Symposium.

Trustees Weigh Plans to Build, Improve Region

A number of plans designed to increase activities and membership in Northeast Region were proposed at and are under considerations by the region's board of trustees. At a meeting in Huntington, W. Virginia October 11 during the annual conference, several activities were considered and steps taken to put some of them into effect. The meeting was presided over by A. F. Minor, American Telephone and Telegraph Corp., New York, regional chairman.

Also present and contributing to the board's fund of useful information were George E. Best, Manufacturing Chemists Association, NACE president, J. Dwight Bird, The Dampney Co., Boston, regional director and T. J. Maitland, American Telephone & Telegraph Co., N. Y., Technical Practices Committee chairman.

Mr. Best described some of the things NACE has under consideration designed to improve the stature of the association and enhance its value to industry. These include recommendations of standards in some fields, and efforts to get recognition of corrosion engineering as a professional field.

Mr. Maitland reported that more than 1600 NACE members are participating in technical committee work, that nine reports were published during 1960, a revised technical committee manual was issued and that steps were taken to provide liaison with various atomic energy groups working on corrosion problems.

Mr. Maitland said that several reports of technical committees were delayed in publication because of deficiencies that required their revision.

To Study Conference Sites

J. Dwight Bird, among other recom-

(Continued on Page 76)

Northeast Region

Well-Oriented Program Given At Huntington Conference

Plans for New York Meeting Are Outlined

An outline of the program for the 1961 Northeast Region conference to be held in New York October 30-November 2 was given at a meeting of the region's board of trustees in Huntington. The board met October 11 at Hotel Prichard during the region's 12th conference.

Russell E. Gackenbach, American Cyanamid Co., New York, conference chairman, told the board that there will be a luncheon meeting instead of a banquet, block tickets will be bought for shows, a social hour would be held and that plant tours are contemplated. The program is scheduled to last 3½ days.

Considerable progress has been made in arrangements for the 1962 region conference to be held at Hotel Sheraton-Ten Eyck, Albany, October 1-3. Edward L. Simons, general chairman, in a letter addressed to the region chairman, A. F. Minor, outlined the technical program and other details. Sherman L. Williams, Knolls Atomic Power Laboratory, Schenectady, N. Y., is general vice-chairman and Norbert D. Greene, Rensselaer Polytechnic Institute, Troy, N. Y., is technical program chairman.

Papers are scheduled on cathodic and anodic protection, internal current protection, anode-cathode distribution and electrochemical mapping; corrosion product formation and crack sites, metallurgical aspects of stress corrosion, theory, film and surface reactions, effect of crystallorgraphic orientation in corrosion, high temperatures, inhibitors, irradiation effects, corrosion test programs. Symposia are to be held on corrosion in the chemical and paper industries, marine environments, energy conversion systems: Fuel cells, propulsion systems and nuclear.

There will be a fellowship hour, banquet and plant trips.

A program well oriented to the interests of Northeast Region members in the industrialized southwestern part of the region was presented at Huntington October 11-14. Technical committee meetings were held for small but interested groups concerned with plastic pipe line wrappings, underground corrosion coordinating committees, stress corrosion cracking, linings, and chemical process corrosion.

The region's 12th annual conference at the Prichard Hotel attracted registrations from more than 230 persons, including ten women and a number from other regions. The technical program of 32 papers was well attended. Six plant tours on the afternoon of October 12 were popular and the banquet attracted over 200.

Arrangements Well Organized

Arrangements for registration, identification of meeting rooms, provision of projection equipment and other accessories was handled efficiently and well by a committee headed by R. G. Schroeder, Standard Ultramarine & Color Co., Huntington. Registration began at noon on Tuesday and except for a few minutes after opening that day and on the following morning, little time was lost waiting by those attending the meeting.

Committeemen working with Mr. Schroeder were active and efficiently organized. The Huntington Chamber of Commerce helped with the registration chores.

All meetings and the banquet were held at the Hotel Prichard.

Final Sessions Popular

Friday morning symposia were well-attended. These were on underground and chemical and refinery industry problems. The latter symposium attracted a standing-room-only audience to hear five papers on a variety of topics from glassed steel to fabrication techniques.

HUNTINGTON CONFERENCE Fellowship Hour guests were (left panel) A. F. Minor, American Telephone & Telegraph Corp., New York, region chairman; R. S. Levy, The Pfaudler Co. (right panel) Monte S. Walker (left) and Leonard C. Rowe, General Motors Corp., Detroit.

Uninformed Citizen Is Peril, Speaker Warns

The United States faces the loss of its freedoms and the destruction of the Republican form of government if a successful effort is not made to better inform its citizens. This was the theme of the principal address made at the annual banquet of Northeast Region at Huntington, West Va. during its October conference. Louis P. Shannon, manager of the extension division, E. I. du Pont de Nemours & Co., Inc., Wilmington, Del. expressed this view and called on his listeners to do their duty as citizens in seeing that their associates and acquaintances are given the true facts about the nation's present problems.

Mr. Shannon cited the principal destructive forces now whittling away at the strength of the nation as confiscatory taxation, inflation, and the dissemination of false information about the true function of business in American life. The nation's youth, especially, he said, is woefully misinformed about the operation, function and attributes of business. Enemies in the Socialist and Communist spheres are constantly spreading misinformation designed to weaken the nation so that it can be taken over easily.

Also making short talks at the banquet were NACE's president George E. Best; R. G. Schroeder, conference general chairman and A. G. Minor, Northeast Region chairman.

1961 Region Nominees

The following have been nominated for 1961 offices in Northeast Region:

For chairman, J. H. Cogshall, Pennsalt Chemicals Corp., Natrona, Pa.

For vice-chairman: Jerome M. Bialosky, Koppers Co., Inc., Verona, Pa.

For Secretary-Treasurer: H. H. Bennett, Mobil Oil Co., Paulsboro, New Jersey, and E. K. Benson, New York Telephone Co., New York.

Niagara Falls in 1963

Northeast Region will hold its 1963 conference at Niagara Falls during the fall at a place and time to be announced later.

COKE BREEZE

Backfill for Anodes

Ideally suited for use with anodes. Has a high carbon content and comes in sizes of ⅛-inch x 0 to ⅜ x ⅛ inch. In bulk or sacks. Prices on other sizes on request.

National Carbon Anodes
Magnesium Anodes
Good-All Rectifiers

WHOLESALE COKE COMPANY

PHONE GARDENDALE, ALA.
HEmlock 6-3603

P. O. Box 94 Mt. Olive, Ala.

℞ FOR SURE PROTECTION

You've made a worthwhile investment in this pipe. You've spent some more on cleaning and coating. Why risk the cost of digging it up in a few years to repair corrosion damage?

With ERP protection you won't need to. Electro Rust-Proofing takes care of those pinpoints of corrosion that even the best coating cannot prevent. When your pipeline is laid, ERP makes a test survey to determine your needs. Once cathodic protection is installed, a periodic service visit by ERP engineers keeps your pipeline new—for good. They adjust your protection as your needs or environmental conditions vary.

ERP installs corrosion protection anywhere . . . at any time. But your greatest savings come if you call ERP early . . . if you plan your protection while you plan your pipeline. Write ERP today—Dept. E.55.27.

ERP CATHODIC PROTECTION SINCE 1935

ELECTRO RUST-PROOFING CORP.

A SUBSIDIARY OF WALLACE & TIERNAN INC.

30 MAIN STREET, BELLEVILLE 9, NEW JERSEY

CABLE: ELECTRO, NEWARK, N. J.

Western Region

Total Attendance of 250 Counted at San Francisco

About 250 attended the October 6-7 Western Regional Division Conference held at the Sheraton-Palace Hotel in downtown San Francisco, Cal.

The conference was begun with a well received talk by NACE Vice President E. C. Greco of United Gas Corp., Shreveport, La., on the lack of science education in this country's secondary schools.

NACE President George E. Best of the Manufacturing Chemists' Association, Inc., Washington, D. C., made a brief after dinner talk following the banquet. He spoke on the steps being taken to up-grade NACE's standing in the technical world.

Conference Chairman George Puckett of Dow Chemical Co., Pittsburg, Cal., was pleased with the attendance and interest shown in the technical program which covered corrosion problems ranging from the nuclear energy field to the chemical process industries.

SECTION CALENDAR

November

2 Teche Section. Petroleum Club.
4 Birmingham Section. Hydroelectric and Steam Plant Construction and Corrosion Problems, by R. S. Woodruff.
8 San Francisco Bay Area Section.
8 Houston Section. Houston Engineers Club.
8 Permian Basin Section.
14 Greater St. Louis Section. Roofing Materials for Chemical Plants, by C. R. Martinson.
14 Kansas City Section.
14 Central Oklahoma Section. Down Hole Corrosion, by W. C. Koger. Tropical Cafeteria, Oklahoma City.
14 North Texas Section. New Techniques of Inhibition in Producing Oil and Gas Wells, by D. R. Fincher.
15 Baltimore-Washington Section. Slide talk on 1960 NACE Conference by C. A. Muller.
15 Chicago Section. Tape Coating Forum and Panel.
15 Alamo Section.
15 Cleveland Section.
17 Vancouver Section.
28 Tulsa Section.
29 Panhandle Section.
29 Southwestern Ohio Section. Underground and Industrial Coatings, by W. E. Kemp. To be held in Cincinnati.

December

6 Ohio Valley Section. Joint meeting with ASM on high temperature corrosion.
7 Teche Section. Petroleum Club.
9 Rocky Mountain Section.
12 Kansas City Section.
12 Greater St. Louis Section.
12 Central Oklahoma Section.
12 North Texas Section. Torch Restaurant, Dallas, 6:30 pm.
13 San Joaquin Valley Section.
13 San Francisco Bay Area Section.
13 Houston Section. Houston Engineers Club.
13 Permian Basin Section.
13 Alamo Section.
13 Twin Cities Section.
15 Vancouver Section. Slide presentation on 1960 NACE Dallas Conference.
20 Cleveland Section.
21 Greater Boston Section. Underground Corrosion of Metallic Structures, by Melvin Romanoff.

California Short Course Registration Totals 60

Total registration of about 60 representing California, Washington, Texas, Japan and Canada was counted at the October 3-5 Short Course in Corrosion held in conjunction with the Western Regional Division Conference. The course was presented by the University of California, Berkeley, and the University of California, Los Angeles, in cooperation with NACE.

The course included a three-hour introduction to the solid state theory in corrosion presented by W. E. Tragert of General Electric Co., Schenectady, N. Y.

Also included were sessions on fundamentals of corrosion, emphasizing recent advances in corrosion knowledge.

Proceedings of this short course will be published and mailed to all registrants.

•

San Francisco Bay Area Section heard George M. Taylor of Hercules Powder Company speak at the October 11 meeting on Penton as a material to combat corrosion.

The November 8 meeting is scheduled to include a discussion on a new instrument for on-stream corrosion inspection. J. Randolph Richards of International Inspection, Inc., is to be the discussion leader.

•

Portland Section had Robert R. Pierce of Pennsalt Chemicals Corp., Natrona, Pa., speak on masonry construction in the process industry for the October 13 meeting.

•

Central Arizona Section has held a meeting to stimulate local interest in NACE. This October 5 meeting included a slide talk on surface preparation of sandblasting by Blair Emery and a talk on selection and application of protective coatings by Charles E. Wilsterman.

Northeast Region

Trustees Weigh—

(Continued From Page 74)

mendations, suggested that the region study past and future locations for regional conferences. In deciding on sites for future meetings, the advantages of holding them in places where NACE sections are organized or may be organized should be weighed. If necessary, the region should seek to have the conferences sponsored jointly by two smaller sections, or when this is impossible, to provide assistance sufficient to make it possible for smaller sections to hold them.

Mr. Bird pointed out that there is urgent need for a big growth in NACE membership in Northeast region and that sections should make every effort to increase it. Cooperation of Central Office is available, he pointed out.

Other Points Covered

Also discussed were regional activity in securing corporate memberships, activity to bring to high school students information about a corrosion control career in engineering, financing regional conferences and others.

The region gratefully acknowledged receipt from Niagara Frontier Section of $300 to be added to the region's treasury. The money was part of the net proceeds of the section's recent symposium on coatings.

Greater Boston Section Mails Program Brochure

A printed brochure has been mailed to all members of the Greater Boston Section to give a complete listing of the section's scheduled meetings through April, 1961. The brochure gives the time, place and technical program for each meeting.

Scheduled programs are given below.

December 21: Underground Corrosion of Metallic Structures, by Melvin Romanoff, National Bureau of Standards.

February 15: Biological Influences on Deterioration of Materials in Marine Environments, by Albert P. Richards of Wm. F. Claff Laboratories, Inc.

April 12: Corrosion in Boilers and Condensate Lines, by Douglas E. Noll of Hall Laboratories, Inc.

All meetings are held at the Beaconfield Hotel with a social hour at 5:30, dinner at 6:30, business meeting at 7:45, guest speaker at 8 and discussion at 9.

•

Baltimore-Washington Section has scheduled a slide-talk on the 1960 Corrosion Show held last March at Dallas for its November 15 meeting.

Officers recently elected by the section are Chairman Herbert F. Lewis, Vice Chairman Neil B. Garlock and Secretary-Treasurer Thomas E. Krehnbrink.

•

Metropolitan New York Section held a Marine Corrosion Symposium for its October 19 meeting. Moderator was G. W. Kurr of American Smelting and Refining Company. A. W. Peabody of Ebasco Services spoke on piers, piling and bulkheads. R. E. Nelson of Socony Mobil Oil spoke on ballast tanks of ships. Hulls of ships was the topic discussed by E. W. Dreyman of Petro-Chemical Associates, and R. Devoluy of Glidden Company spoke on coatings.

•

Kanawha Valley Section recently appointed the following committee chairmen: W. R. Lambert of United Fuel Gas Co., program; J. A. Parker of United Fuel Gas Co., arrangements; George C. Cox, consultant, publicity; and J. M. Bates of Union Carbide, section trustee.

•

NACE's 18th Annual Conference and 1962 Corrosion Show will be held March 18-22, 1962, at the Municipal Auditorium in Kansas City, Mo.

CORROSION ABSTRACTS

INDEX TO CORROSION ABSTRACTS

Vol. 16 November, 1960 No. 11

3. CHARACTERISTIC CORROSION PHENOMENA
3.7 Metallurgical Effects 77
3.8 Miscellaneous Principles 78
5. PREVENTIVE MEASURES
5.3 Metallic Coatings 78
6. MATERIALS OF CONSTRUCTION
6.2 Ferrous Metals and Alloys 80
6.3 Non-Ferrous Metals and Alloys—Heavy 81
6.4 Non-Ferrous Metals and Alloys—Light 82
6.5 Metals—Multiple or Combined 84
6.6 Non-Metallic Materials 84
6.7 Duplex Materials 85
8. INDUSTRIES
8.4 Group 4 85

3. CHARACTERISTIC CORROSION PHENOMENA

3.7 Metallurgical Effects

3.7.3, 6.3.20

Electron-Beam Welding. Experimental Results Achieved by the Initial Development Investigation and Their Applications are Described. G. Burton, Jr. and L. Frankhouser. Westinghouse Electric Corp. Welding J., **38,** 401s-409s (1959) Oct.

A high-voltage electron-beam welding machine with a maximum beam power of 1 kw was used to make butt-joint weld penetration up to 0.250 in. in Zircaloy-2. Chemical analyses, metallography, corrosion tests, and mechanical-property evaluations have revealed satisfactory properties in the Zircaloy-2 welded by this process. The high-voltage (50 to 100 kv) electron-beam equipment has distinct advantages for extreme concentration of welded heat not realized with other processes nor with low voltage (5 to 50 kv) electron beam equipment. As a result, potential production applications are foreseen in welding fuel assemblies for the nuclear reactor industry. (auth)—NSA. 19633

3.7.3, 5.12, 6.4.2

Shortening the Heat-Treatment Regime for Parts of AL9 Alloy. (In Russian.) I. A. Nikiforov. Metalloved. i Termicheskaya Obrabotka Metallov (Metal Sci. and Heat Treatment of Metals), No. 5, 58-59 (1959).

The heat-treatment schedule for AL9 aluminum alloy (silicon 6-8, magnesium 0.2-0.4 percent) was water-quenching from 535 C followed by 5 hrs. at 170 C. Determination of the UTS, elongation, and hardness of specimens aged for 30-180 minutes at 175-215 C showed that the best mechanical properties were obtained after ageing for 120 minutes at 200 C. Dilatometric measurements indicated that the rate of dimensional change sharply increased as the ageing temperature increased from 170 to 190 C; with specimens aged at 220 C, the dimensional changes were complete after 1 hr. Variations in ageing conditions had little effect on corrosion-resistance to 3 percent NaCl solution.—MA. 19341

3.7.2, 6.2.2

Effects of Rare Metals on Mechanical Properties of Iron-Aluminum Alloys. (In Russian.) E. M. Savetskii, V. F. Terekhova and I. V. Burov. Metalloved. i Termicheskaya Obrabotka Metallov. (Metal Science and Heat-Treatment of Metals), No. 3, 38-43 (1959) March. Translation Available from Henry Brutcher, Technical Translations, P. O. Box 157, Altadena, Calif.

Possibility of improving the mechanical properties, of iron-15 percent aluminum alloys by addition of Zr, Ti, Ta, Cb, V, B, Mo, and Cb. Starting materials and preparation of alloys. Microstructures. Mechanical properties. Magnetic and technological properties. Principal embrittling impurity and how to minimize it. Additions refining the grain. Addition elements increasing the hardness. Workability of magnetic Fe-Al alloys. Oxidation and corrosion resistance compared with that of stainless steel. Economy of Fe-Al compositions alloyed with small amounts of Ce, Zr, Ta, etc.—HB. 19499

3.7.3, 6.4.3

Joining of Beryllium. N. E. Weare and R. E. Monroe. Battelle Memorial Inst. Light Metal Age, **17,** No. 7/8, 10-12 (1959) Aug.

Reviews brittleness and toxicity as problems peculiar to beryllium, considers surface preparation of beryllium joints, and discusses methods of joining beryllium, namely fusion welding, resistance welding, solid-state welding and brazing. Joints have been made between beryllium and other metals such as nickel, stainless steel and copper, using copper filler metals, but better results were obtained using silver and silver-copper eutectic alloy. Photomicrographs, 16 references.—INCO. 19537

3.7.2, 3.2.2, 6.2.3

The Influence of Minor Elements on the Isothermal Embrittlement of Steels. W. Steven and K. Balajiva. J. Iron and Steel Inst., **193,** Pt. 2, 141-147 (1959) Oct.

Tests on steels of controlled purity show that isothermal embrittlement is due to presence of traces of impurities such as P, As, Sb and Sn and not to presence of C and normal alloying elements Ni, Cr or Mo. A steel containing C, Ni, Cr and Mo, but substantially free of trace elements, is not susceptible to embrittlement within 1000 hrs. at 450 C. Presence of P, Sb, As, Sn, Mn or Si promotes susceptibility to embrittlement at 450 C. Most potent of these elements is Sb. Presence of small percentages of Bi, Co, Cu, Ge, Ga, Zr or N_2, at least up to levels studied in this investigation, does not induce susceptibility to embrittlement at 450 C. Mo retards, but does not prevent, development of embrittlement. Brittle fractures of steels susceptible to embrittlement are substantially intergranular. Details of preparation of steels (of nominal composition 0.3 C-3.0 Ni-0.75 Cr, in some cases containing also 0.5 Mo) by powder-metallurgy or by vacuum-melting (latter method was preferred) are given in Appendix I, and methods of analysis adopted are outlined in Appendix II. Experimental data are presented in graphs and tables. Degree of embrittlement was assessed by shift of impact-transition range. Micrographs show fractures of 3 of steels tested. 7 references.—INCO. 19531

3.7.3

Rust Resistance of Fluxes. (In Czech.) Eugen Stalmasek. Zvaranie, **8,** 290-299 (1959) October.

The problem of welding on corrosion attacked surfaces. Rust resistance determined by adding uniformly distributed rust to the filler material over the weld. Humidity and welding temperature influence the resistance. 10 references.—RML. 19530

3.7.3, 6.3.20

How to Weld Zirconium and Its Alloys. L. E. Stark. Mallory-Sharon Metals Corp. Welding Engr., **44,** No. 10, 50-51 (1959) October.

To retain desirable nuclear and mechanical properties and corrosion re-

Abstracts in This Section are selected from among those supplied to subscribers to the NACE Abstract Punch Card Service. Persons who are interested in reviewing all available abstracts should write to NACE for information on this service.

PHOTOPRINTS and/or MICROFILM COPIES

of Technical Articles Abstracted in

Corrosion Abstracts

May Be Obtained From

ENGINEERING SOCIETIES LIBRARY, 29 West 39th Street, New York 18, N. Y.

CARNEGIE LIBRARY OF PITTSBURGH, 4400 Forbes St., Pittsburgh 13, Pa.

NEW YORK PUBLIC LIBRARY, New York City.

U. S. DEPT. OF AGRICULTURE LIBRARY, Office of Librarian, Washington, D. C. (Special forms must be secured).

LIBRARY OF CONGRESS, Washington, D. C.

JOHN CRERAR LIBRARY, 86 East Randolph St., Chicago 1, Ill.

Persons who wish to secure copies of articles when original sources are unavailable, may apply directly to any of the above for copies. Full reference information should accompany request. The National Association of Corrosion Engineers offers no warranty of any nature concerning these sources, and publishes the names for information only.

NACE will NOT accept orders for photoprint or microfilm copies of material not published by the association.

sistance, fabrication by arc welding is recommended. To combat detrimental effects of O_2, H_2 and N_2 absorption, arc welding must be conducted in high-purity inert atmosphere, in dry-box when welding is critical. Arc welding details are presented, and microstructure of weld and heat affected zone is discussed. Table gives physical and mechanical properties for Zr, Zircaloy-2 and Zircaloy-3.—INCO. 19529

3.7.3, 6.2.5

How to Get Better Stainless Steel Welds. W. L. Wilcox. Arcos Corp. Welding Engr., **44,** No. 9, 32-34 (1959) Sept.

Review covers definition of stainless steels, classification of stainless welding electrodes based on weld deposit chemistry, standard color coding of electrodes, numbering system set up by AWS, functions of electrode coating, problems of weld porosity and underbead cracking, control of magnetic arc to prevent fingernailing of electrode coating, advantages of using d-c reverse polarity and stringer bead technique for welding stainless and influence of alloying elements in electrode.—INCO. 19587

3.8 Miscellaneous Principles

3.8.2, 3.6.8, 6.3.11

Transport of Hydrogen Through Palladium-Clad Electrodes. S. Schuldiner and J. P. Hoare. U. S. Naval Res. Lab. Paper before Symp. on Charge Transfer Processes, Univ. Toronto, Sept. 4-5, 1958. Can. J. Chem., **37,** No. 1, 229-237 (1959) January.

Electrochemical polarization studies of transport of H through Pd, Pt and Pd-clad Pt, Au, Ni and Fe conducted under conditions of concentration gradient of either atoms or protons. Transport of H through atom concentration gradient was found for Pd and Pd-clad Fe only. Under proton concentration gradient, protons migrated readily through Pd, but their transfer through Pt was immeasurable unless Pt was sandwiched between Pd. Transfer of protons through Fe sandwiched between Pd was also found. H atoms did not dissolve to significant extent in Pt, but if protons are introduced from Pd-cladding to Pt they can, under proper conditions, migrate through Pt. Solution and diffusion of H atoms and migration of protons occurred in Fe. Transport of H, in any form, through Au and Ni was not detected. Considering electronic configuration of these metals, it was surprising that protons did not migrate through Ni. Reasons for this anomaly are suggested. Graphs.—INCO. 19511

3.8.2, 3.6.8, 3.8.3, 3.8.4, 5.8.1

The Fundamentals of Wet Corrosion, Its Manifestations and Mitigation. F. P. A. Robinson. South African Ind. Chem., **13,** 120-130 (1959) June.

Outline of electrochemistry of corrosion in terms of polarization, passivity, oxide film formation and electron configuration in metals. Methods of corrosion inhibition.—RML. 19432

3.8.4, 6.3.21

Diffusion of Oxygen in Hafnium. J. Paul Pemsler. Nuclear Metals, Inc. U. S. Atomic Energy Commission Pubn., NMI-1213, April 17, 1959, 7 pp. Available from Office of Technical Services, Washington, D. C.

The diffusion of oxygen in hafnium was studied in the temperature range 500 to 620 C by observing the rates of dissolution of anodically deposited interference oxide films. The diffusion coefficient obeys the equation $D = D_0 \exp(-51{,}800/RT)$ where the value of $D_0 = 1.4$, 0.47, or 0.14 cm^2/sec depending on whether the value of the saturation concentration of oxygen in hafnium is assumed to be 20, 30 or 40 at. percent. (auth)—NSA. 19362

5. PREVENTIVE MEASURES

5.3 Metallic Coatings

5.3.2, 2.2.2, 4.2.1, 3.4.7

Zinc Coatings on Iron and Steel. Pt. 3. Corrosion Resistance of Zinc Coatings. A. K. Parker. Metal Finishing J., **5,** 445-453 (1959) Dec.

Behavior of zinc and zinc coatings in atmospheric exposure tests. Sulfur pollution is a determining factor for the intensity of corrosion. Corrosion resistance of zinc in contact with liquids, particularly effect of pH value. 19 references.—RML. 19368

5.3.2, 6.2.4

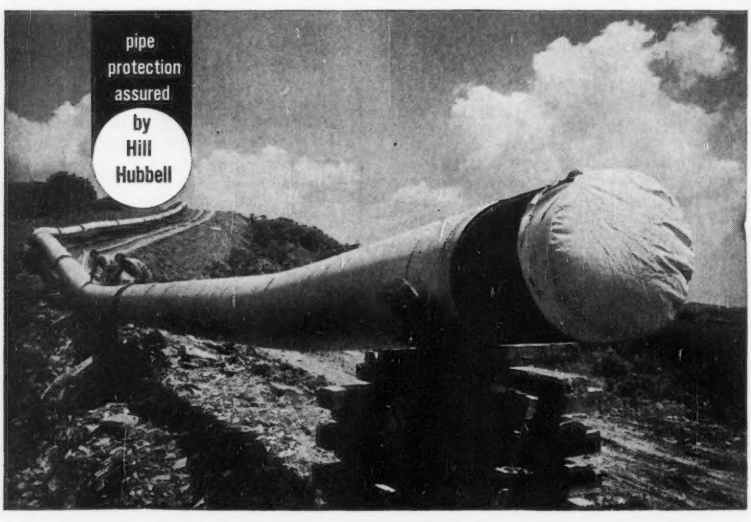
High Temperature Coatings for Chromium Hot Work Tool Steels. Period Covered: January 1957 to June 1958. Elwood B. Norris. Metcut Research Associates, Inc. U. S. Wright Air Development Center, Technical Rept. 58-269, July 28, 1958, 90 pp. Available from Office of Technical Services, Washington, D. C. (Order PB 151423).

Chromium hot work tool steels are normally useful to approximately 1000 F provided that they are protected from corrosive atmospheres. A typical 5 per cent chromium tool steel, Thermold J, was used to study the protective qualities of various plated, dipped, or sprayed coatings. In addition to investigating the oxidation and corrosion protection, selected coatings were checked for their effect on tensile, stress-rupture and fatigue properties of the base metal at room and elevated temperature. The relative resistance of the selected coatings to abrasion and thermal shock was also studied. From a corrosion standpoint, the best of the coatings investigated were Ni-Zn, Aluminizing, Alumicoat and Ni. Of the selected coatings, Aluminizing and Alumicoat reduced the strength of the base metal because of the high temperatures encountered during coating. Al-Si paint was the only coating which did not significantly reduce the fatigue strength. Watts Ni had high thermal shock resistance. Electroless nickel had the best abrasion resistance. (auth.)—NSA. 19353

5.3.4, 8.4.5

Cladding of Reactor Fuel Elements. (In Czech.) Bohumil Prenosil. Hutnické Listy, **13,** No 4, 330-334 (1958) April.

The metallurgical aspects of the problems connected with the cladding of nuclear fuel elements with various metals, such as aluminum, magnesium, zirconium and stainless steel, together with their behavior as a function of temperature, are analyzed. The phase evolution of the uranium-aluminum system is studied, diffusion and corrosion phenomena of the metals concerned are evaluated and compared. —ALL. 19419



rugged cross-country pipe line *fully protected*

To be practical, performance life of inaccessible installations such as this must be measured in decades. That's why Hill Hubbell was chosen to apply optimum corrosion protection to this and many similar lines throughout the country.

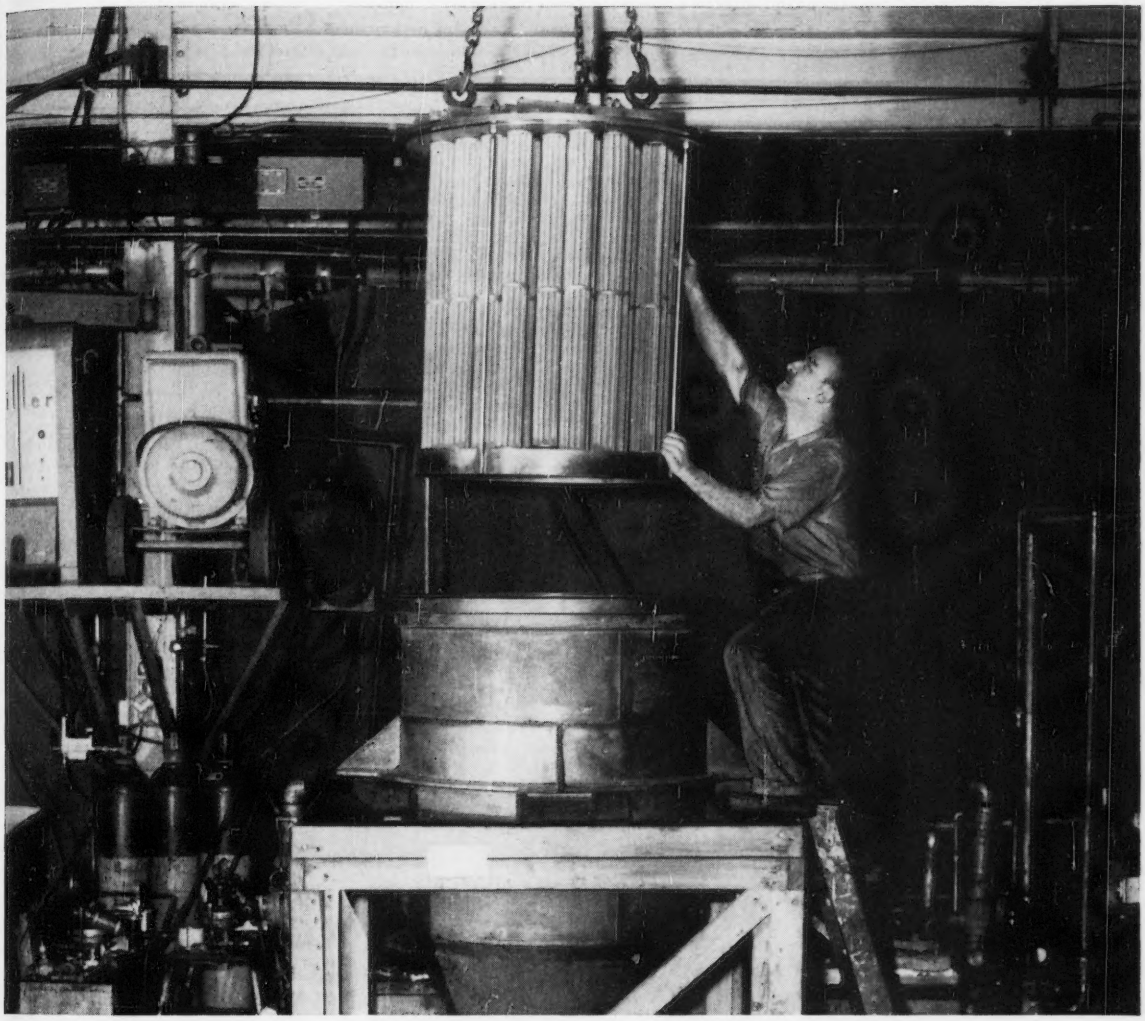
On your next job be assured of long service life — specify Hill Hubbell, the name synonymous with quality in mill coated-and-wrapped pipe.

Specify Hill Hubbell wrapped pipe on your next job . . .

HILL HUBBELL

3091 MAYFIELD RD. • CLEVELAND 18, OHIO • YELLOWSTONE 2-7535

154a



Built to withstand highly corrosive fluorine-containing gases, Monel nickel-copper alloy porous sintered filter elements are lowered into shell. Entire unit, including housing was constructed by Purolator Products, Inc., Rahway, N. J.

Filters most corrosive element known ...with porous sintered Monel

This filter reclaims solid particles from a gaseous stream containing fluorine — the world's most reactive element. It's made of porous sintered Monel* nickel-copper alloy, stands up in fluorine service much longer than filters of other materials. Housing and cover are Monel, too.

Porous metal filters of Monel and other Inco Nickel Alloys are proving invaluable wherever corrosion, cyclic shock, heat or radioactivity must be reckoned with. They're made with pore sizes from 50 down to 0.2 microns, ± 10%.

For high-temperature filtering . . . particularly above 1000° F, porous sintered Inconel* nickel-chromium alloy is used . . . for filtering such materials as molten sodium and potassium and removing catalyst particles from gaseous products of catalytic cracking units.

For low-temperature filtering . . . handling liquid helium, liquid oxygen. Here, porous Monel alloy and Nickel stand up where glass or cellulose fibers break up . . . retain useful properties even below minus 450° F.

In many areas of the expanding nuclear industry, Inco Nickel Alloys provide useful combinations of corrosion resistance, strength at both low and high temperatures, good thermal and electrical properties.

Our new booklet "Handling Fluorine and Fluorine Compounds with Inco Nickel Alloys" shows many industry-proven applications. Yours for the asking from Inco.

*Registered trademark

Huntington Alloy Products Division
The International Nickel Company Inc.
Huntington 17, West Virginia

INCO NICKEL ALLOYS

155a

5.3.2

Corrosion Protection. Stephen Y. Scott. Paper Presented at Second International Metal Spraying Conf., Birmingham, 1958. Iron and Steel, **31,** 589-592 (1958) Dec.

Aluminum sprayed coatings at the National Steelworks, Aviles, Spain. Parts sprayed included gasholders, gas mains and blast furnaces. Results of accelerated corrosion tests are given from the point of view of adherence, prosity and rust staining.—MR. 19474

5.3.4

Experience with Corrosion-Resistant Chromized Steel Bolts. E. Taubert. Draht, **9,** No. 505-507 (1958)

Methods of chromizing are briefly described, and the nature, properties and practical merits of the chromized-surface layer are discussed. Seizing of chromized nuts can be prevented by a special treatment. The uses of chromized fasteners are listed.—MA. 19566

5.3.4, 6.2.2

Attempts to Improve Chemically Deposited Titanium Coatings on Iron. M. E. Straumanis and Y. P. Huang. Metall, **12,** No. 6, 501-503 (1958).

Titanium coatings on iron produced by immersion in a molten 90 per cent NaCl-10 per cent TiO_x (containing 2.8-5.6 per cent oxygen) bath at 1000 C for 3 hr. are porous, the pores showing up yellow when the article is immersed in a 2 per cent NaCl solution. Porosity can be considerably reduced, and corrosion-resistance (to immersion for 10 days in 2 per cent NaCl solution) enhanced by the following procedure: (1) dipping the iron article in a $CuSO_4$ or $AgNO_3$ solution to produce a thin surface film of Cu or Ag; (2) treatment in an 85 per cent NaCl-15 per cent TiO_x mixture, under He, for 1 hr. at 1000 C; (3) cooling, and a repetition of the initial operation, which seals the pores in the Ti coating, and (4) further treatment for 3 hr. in the fused NaCl-TiO_x mixture. In each of the operations (1) and (3) the Ti coating produced should weigh 8-10 mg/cm².—MA 19527

6. MATERIALS OF CONSTRUCTION

6.2 Ferrous Metals and Alloys

6.2.2, 6.3.4, 6.3.10, 3.5.9

Investment-Cast Alloys for High-Temperature Service. D. R. Wood. Paper before Brit. Investment Casters' Assoc., 1st Annual Conf., London, May 11-12, 1959. Foundry Trade J., **106,** No. 2225, 663-668 (1959) June 4.

Reviews available alloys, heat-treatment, high-temperature mechanical properties, corrosion resistance, thermal fatigue, and foundry techniques. Data are included for G. 18 B, WF.176 and HR Crown Max (Fe base alloys); HS.31 or X-40, S-816 and G.34 (Co base alloys); and Nimocast 242, G.39, Nimocast 90, GMR-235 and Nimocast 258 (Ni base alloys). Tables and graphs present following data: composition; 100-hr. stress to rupture; room temperature tensile properties; fatigue data; tensile strength, elongation, and 0.2 percent proof stress versus temperature; oxidation after 100 hr. at 750-1,050 C; corrosion resistance in molten Na_2SO_4/NaCl at 900 C; tensile and stress-rupture properties for air- and vacuum-cast alloys and for test-pieces cut from Nimocast 90 rotar castings. 18 references.—INCO. 19575

6.2.5, 3.5.9, 2.3.6

Studies of Local and General Corrosion of Austenitic Chromium-Nickel Steel During Thermal Treatment and Etching. (In Russian.) A. V. Shreiderder, E. M. Kontsevaya and V. P. Gamazov. J. Applied Chem. (Zhur. Prikladnoi Khim.), **32,** No. 7, 1509-1515 (1959) July.

Corrosion and etching tests were made on austenite steels OX18H9 (0.06 percent C, 17.0 percent Cr, 0.20 percent Mn, 8.5 percent Ni, 0.035 percent P, 0.020 percent S, and 0.80 percent Si), 1X18H9 (0.15 percent C, 18.3 percent Cr, 0.2 percent Mn, 8.8 percent Ni, 0.030 percent P, 0.025 percent S, and 0.8 percent Si), 1X13H4G9 (0.25 percent C, 16.7 percent Cr, 7.4 percent Mn, 4.3 percent Ni, 0.03 percent P, 0.025 percent S, and 0.33 percent Si) and heat resisting nickel-chromium alloy (0.11 percent C, 20.0 percent Cr, 0.45 percent Fe, 0.8 percent Mn, 78.0 percent Ni, 0.015 percent P, 0.010 percent S, 0.81 percent Si and 0.15 percent Ti) at elevated temperatures.—NSA. 19459

6.2.5, 3.5.8, 8.4.5

Stress Corrosion of Stainless Steel and Boiler Water Treatment at Shippingport Atomic Power Station. W. J. Singley, I. H. Welinsky, S. F. Whirl and H. A. Klein. pp. 748-766 of "Proceedings of the American Power Conference, March 31, April 1-2, 1959, Volume XXI," 1959. Illinois Institute of Technology, Chicago, Ill.

Following initial operation of the Shippingport Atomic Power Station, leaks were discovered in the stainless steel tubes of one steam generator. The investigations which were conducted to determine the causes of the tube failures are discussed. Tubing failures in the 1-B heat exchanger, boiler water treatment, operating and laboratory tests, and corrective action taken to alleviate the problem are considered—NSA. 19471

6.2.2, 3.4.6

Effect of the Oxygen Pressure on the Oxidation Rate of Pure Iron. (In German.) Alfred Rahmel and Hans-Jurgen Engell. Arch. Eisenhuttenw., **30,** 743-746 (1959) Dec.

Pure iron is exposed to the action of oxygen-argon mixture at a partial pressure of oxygen of 7-760 torr or to pure oxygen of 100-760 torr pressure at temperatures from 700-950 C. Effect of time, pressure and temperature on oxidation. Within the range of the experiment, no influence of the oxygen pressure on the oxidation process was observed. 15 references.—RML. 19383

6.2.2, 3.5.6, 8.8.5

Survey of the Oxidation Processes in Cast Iron. (In Hungarian.) Gyula Nandori. Kohaszati Lapok-Ontode, **92,** 70-77 (1959) Feb.-Mar.

The inter-dendrite porosity in cast iron affecting the strength of casting is attributed to the presence of oxygen introduced from the ambient atmosphere by air passing through the melt and by the oxygen content of the charge. 12 references.—RML. 19356

6.2.3, 3.5.8, 8.4.2

The Stress-Corrosion Cracking of Mild Steel in Coal Gas Liquors. R. N. Parkins and R. Usher. J. Applied Chem., **9,** Pt. 9, 445-456 (1959) Sept.

A field survey and laboratory experiments using synthetic liquors, have indicated chemical conditions under which cracking is likely to be observed in coal-gas cleaning plants. Incidence of failure in various items of a typical plant can be related to chances of these conditions arising at that point in cleaning train. Conditions are not particularly critical with respect to composition. It is tentatively suggested that cyanides permit grain boundaries of mild steel to be corroded and cracks to propagate, by forming soluble complexes with iron in alkaline solutions. Stress-corrosion cracking is likely to occur at any point along a coal gas cleaning train if liquor existing there has a composition lying within a certain range. Extent of this composition range can be defined in terms of concentrations of NH_3, H_2S, CO_2 and HCN occurring within liquor and lies, approximately, between limits of 1 and 2 equivalent of either free NH_3 or total acids. Tables, graphs, photomicrographs, 20 references.—INCO. 19363

6.2.3, 3.7.2, 3.5.8

The Effect of Alloying Mild Steel Upon Its Resistance to Stress-Corrosion Cracking. R. N. Parkins and A. Brown. J. Iron & Steel Inst., **193,** Pt. 1, 45-47 (1959) Sept.

Determination of effects of additions of Al, Cr and Cu to mild steel. Majority of tests were carried out in a boiling aqueous solution containing 860 g. Ca $(NO_3)_2$ and 30 g. NH_4NO_3 per liter of solution. A few tests were carried out in a $Ca(NO_3)_2$ solution containing 650 g/l, to which $CuSO_4$ was added in varying amounts. Method of testing is described and results discussed. Cu containing steels, although known to be useful in resisting certain types of corrosion, are more prone to cracking in nitrate solutions than are unalloyed mild steels. Cr additions increase resistance to cracking, and Al up to 1 percent prevented any grain-boundary attack under conditions of testing employed. Tables, graph, photomicrographs, 8 references.—INCO. 19365

6.2.5, 3.2.2, 3.7.3

Effect of Resistance Heating on the Properties of Cold-Rolled Stainless Steel. (In Russian.) L. V. Mironov, V. G. Sazonov, V. V. Levitin and N. M. Rodigin. Metalloved. i. Term. Obrabotka Metallov, No. 1, 26-30 (1959) Jan. Translation available from Henry Brutcher, Technical Translations, P. O. Box 157, Altadena, Calif.

Mechanical properties, recrystallization giving microstructures and resistance to intergranular corrosion of stainless steels as affected by electric resistance heating compared with ordinary heating. Compositions studied: (a) 0.14 percent carbon, 17.60 chromium, 9.50 nickel, 1 manganese; (b) 0.11 percent carbon, 17.7 chromium, 10.2 nickel, 1 manganese, 0.55 titanium; (c) 0.21 percent carbon, 12.7 chromium, 4.3 nickel, 9.4 manganese; as 1 mm (0.04 in) strip. Reason for higher recrystallization temperatures of resistance heated strip. Heating rates required for good resistance to intergranular corrosion in titanium-stabilized steel strip. 4 figures.—HB. 19335

6.2.4

Design Information on 5 Cr Alloy Steels for Aircraft and Missiles. F. R. Morral, R. J. Favor and W. P. Achbach. Battelle Memorial Inst. Rept. on Contract AF 18(600)1375, August 28, 1959, 48 pp. Available from Office of Technical Services, Washington, D. C. (Order PB151072).

This report is a summary of design information pertinent to the use of the 5 Cr-Mo-V(H-11 type) alloy steels in

aircraft and missile applications. Heat treatment, melting practice and corrosion protection are considered. Manufacturing problems such as machining, forming and joining are also briefly discussed. Data on the elevated-temperature mechanical properties of these H-11 type steels have been collected and evaluated. The presentation and evaluation of these data were in accordance with procedures employed by the ANC-5 Committee.—GRR. 19326

6.2.2, 3.7.2

Iron-Aluminum Base Alloys—Cheap Stainless of the Future. B. King, J. J. Mueller, N. N. Ida and F. G. Tate. Martin Company. Paper before SAE, Summer Mtg., Atlantic City, June 8-13, 1958. Trans. Soc. Automotive Engrs., **67,** 335-342 (1959).

Iron-aluminum base alloys exhibit unsurpassed oxidation resistance. There are indications that aluminum and chromium in combination impart room-temperature corrosion resistance to iron in much the same manner that chromium alone does. Iron-aluminum base alloys tend to be deficient in room-temperature ductility, in weldability, in high-temperature strength and in their susceptibility to work-hardening. However, their qualities can be improved by means of alloying additions and through refinement of preparation and heat-treating methods. Experimental alloys prepared by The Martin Co. (5.5 w/o aluminum, 9.5 w/o chromium and 7.5 w/o aluminum, 5 w/o chromium) compare favorably in strength and ductility at both high and low temperatures with ferritic stainless steels. Photomicrographs, graphs. 11 references.—INCO. 19259

6.3 Non-Ferrous Metals and Alloys—Heavy

6.3.16, 5.3.2

Conference on Research in Progress on Tungsten. Held in Durham, N. C., May 20-21, 1959. Contents: 25 papers, 121 pp. Office of Ordnance Research, Durham, N. C. Available from Office of Technical Services, Washington, D. C. (Order PB 161013).

The following papers are of interest to the corrosion engineer: Studies of Tungsten Coatings; Flame Spraying Tungsten with Gas Stabilized Arc; A Preliminary Study of the Protection of Tungsten by Coating of Rhodium; Fundamental Study of the Oxidation of Tungsten; Oxidation of Tungsten; The High Temperature Oxidation of Tungsten-Niobium alloys. 19375

6.3.20, 3.8.4, 3.7.2

Oxidation of Zirconium and Zirconium Alloys. H. A. Porte, J. G. Schnizlein, R. C. Vogel and D. F. Fischer. Argonne National Lab. U. S. Atomic Energy Commission Pubn., ANL-6046, September, 1959, 42 pp. Available from Office of Technical Services, Washington, D. C.

Zirconium oxidation was investigated in the temperature range 400-900 C at oxygen pressures of 50, 200, and 800 mm. The reaction rate of massive (parallelepiped) samples was best expressed by the cubic rate law. At an oxygen pressure of 200 mm the activation energy was calculated to be 42.7 kcal per mole and the cubic rate constant in (μ g per sq cm) per minute can be expressed as $k = (5.94 \times 10^{16})e^{-42,700/RT}$. The oxidation rate was found to be relatively insensitive to various types of surface preparations in the temperature range 400 to 700 C. No dependence of reaction rate on oxygen pressure was observed. The cubic rate law also was obeyed by foil specimens at 700 C; however, the rate constants were slightly larger than values obtained from parallelepiped samples. The oxidations of zirconium binary alloys containing nominally 1, 2 and 4 atom percent aditives of Al, Be, C, Cr, Co, Cu, Hf, Fe, Pb, Mo, Ni, Nb, Pt, Si, Ta, Sn, Ti, W, U and V were studied at 700 C and 200 mm oxygen. The alloys were grouped according to 4 types of oxidation behavior. Two groups consisted of alloys which oxidized according to the cubic rate law (Group I) or parabolic rate law (Group II) and did not exhibit breakaway phenomena. The other groups were alloys which initially oxidized according to the cubic rate law (Group III) or parabolic rate law (Group IV) but later exhibited breakaway oxidation phenomena. For alloys of those aditives which are soluble in zirconium the initial oxidation rates are explained according to a valency effect in terms of the Wagner-Hauffe theory of alloy oxidation. For additives insoluble in zirconium, no single theory is felt to be adequate. The breakaway phenomena observed for many of the alloys is explained in terms of a 15 percent deviation of the additive ionic radius from the ionic radius of Zr^{4+}. Some X-ray and electron diffraction studies, which indicate that for zirconium and some of its alloys the breakaway occurs as a result of a polymorphic transformation in the zirconium dioxide film, were made. (auth)—NSA. 19391

6.3.6, 8.8.5, 8.10.2

Copper and Copper Alloys: A Survey of Technical Progress During 1958. Pts. I, II. E. Voce. Metallurgia, **59,** Nos. 352, 353, 88-92, 131-138 (1959).

Pt. I. Principal items of interest are discussed, such as raw-material resources, extraction, fabrication, properties, etc.

Pt. II. The properties of copper and its alloys, including corrosion-resistance and joining ability, are reviewed. Powder and physical metallurgy and analysis are also dealth with.—MA. 19585

6.3.10, 4.3.6

Action of Some Dilute Salt Solutions on Monel Metal. Charles F. Poe and L. M. Dye. University of Colorado Studies, No. 2, 61-64 (1959).

Monel metal submerged in various salt solutions of different concentrations for tabulated times. Loss in weight recorded showed very slight corrosion. 13 references.—RML. 19400

6.3.11, 3.5.9

Internal Oxidation of Silver and Silver Alloys. (In German.) H. Spengler. Metall, **13,** 646-652 (1959) July.

Velocity of internal oxidation of 99.9-99.999 percent pure gold and silver-cadmium alloys as a function of temperature and time. Effects of internal oxidation on hardness and electrical conductivity. 10 references.—RML. 19412

6.3.11, 3.8.2, 5.2.1, 5.3.4

Electrochemical Properties of the Platinum Metals. M. J. N. Pourbaix, J. Van Muylder and N. de Zoubov. Platinum Metals Rev., **3,** No. 2, 47-53 (1959).

The concept and construction of potential/pH diagrams is described. The corrosion properties of platinum, cathodic protection, electrodeposition of platinum, and the stability and formation of the oxides of platinum are discussed in terms of the diagram.—MA. 19408

PRIME and COMPETITIVE
Anti-Corrosion
PIPELINE MATERIALS

- Asbestos felt and Rockshield
- Glass Pipeline Wraps
  Mfd. by Owens-Corning Fiberglas Corporation
- Tapes
- Kraft Wraps
- Casing Seals
  Mfd. by Irish Pipe Line Supply Co.
- Alpon Internal Pipe Coating
  (Epoxy Coating)
- Tar Clad
  (Coal Tar Epoxy Coating)

GOOD SERVICE . . . . . SPECIFICATION MATERIALS

Perrault Supply

A SERVICE OF ALLIED PAINT DIVISION
H. K. PORTER COMPANY, INC.
2300 N. LEWIS — BOX 1088 — TULSA, OKLA., LUther 7-0101
45 ROCKEFELLER PLAZA • NEW YORK 20, N. Y. • PLaza 7-8265

AINSLIE PERRAULT V. V. MALCOM

157a

6.3.10, 3.5.8

A Comparison of the Creep-Rupture Properties of Nickel in Air and In Vacuum. Paul Shahinian and M. R. Achter. Amer. Inst. Mining & Met. Engrs. Conf. on High-Temperature Materials, 1957, **1959,** 448-465.

At low stresses, Ni is more creep-resistant in air than in vacuo, but at high stresses the reverse is true. This reversal is explained by assuming that air strengthens Ni by an oxidation mechanism, but weakens it by lowering its surface tension, and that the controlling factor is the strain rate. 13 references.—MA. 19480

6.3.6, 8.8.5, 7.7

Copper and Copper Alloy Castings for High-Conductivity Applications. A. H. Rollins. Copper, No. 6, 12-18 (1959).

Cu castings can be guaranteed by some foundries to have ⩽ 97 percent conductivity I.A.C.S. For applications where this is unnecessary an adition of 1 percent Sn, Zn or Cd is made to enhance machinability, corrosion-resistance, and YS. The addition of approximately 0.3-0.6 percent Te provides an alloy almost as easy to machine as free-cutting brass, with a reduction in conductivity ⩾ 3 percent. The use of Cu-Cr alloys in electrical applications is noted and tables show the influence of heat-treatment on the properties of such castings and the properties of HC Cu casting alloys after heat-treatment. Other Cu alloys for electrical purposes are grouped into those containing traces of Be and relatively large amounts of Co, and the reverse. 14 references.—MA. 19446

6.3.10, 6.2.2, 3.8.4, 3.5.8

Oxidation of Experimental Alloys. J. C. Richmond and H. R. Thornton. National Bureau of Standards. U. S. Wright Air Development Center, U. S. Air Force, Feb. 1959, 19 pp. Available from Office of Technical Services, Washington, D. C.

Information is presented concerning the oxidation resistance of five new high-temperature sheet alloys—two nickel-molybdenum-chromium alloys and three iron-chromium-aluminum alloys. The average depth of external oxidation and maximum depth of oxide penetration were measured for specimens subjected to stress in air at high temperatures for 100 hrs., and on specimens stressed in air under fluctuating-temperature conditions for 100 hrs. Weight changes of specimens oxidized in air at high temperatures were recorded during the tests. Stresses below that required to produce 1 percent extension in 100 hrs. showed little effect. The new alloys conformed reasonably well to the parabolic rate law in weight-gain oxidation tests.—OTS. 19441

6.3.6, 3.8.4, 3.8.2

Kinetics of the Dissolution of Copper and Graphic Presentation of its Performance by Means of Corrosion Current pH Diagrams. (In German.) Lj. Rubinić and T. Marković. Werkstoffe u. Korrosion, **10,** No. 11, 666-668 (1959) November.

The dissolution of electrolytic copper in electrolytes has been investigated by observing the corrosion current i_o. The dissolution rate in 0,25N-NaCl and 0,25N-KH_2PO_4 is governed by the exponential relationships $i_o = 0{,}20.t^{1.67}$ and $i_o = 0{,}08.t^{0.605}$, respectively. The dissolution rate in 0,5N-KNO_3 is governed by the linear relation $i_o = 0{,}08.t$, where t is the duration of the test. The present paper is exclusively concerned with the graphic presentation of the performance of electrolytic copper and brass 70 in the form of the corrosion current/pH diagram. 19507

6.3.20, 3.5.9, 3.8.4

Mechanism of Oxidation of Zirconium at High Temperature. (In French.) G. Sainfort. Mém. Sci. Rev. Mét., **56,** 704-712 (1959) December.

Kinetics of oxidation of Zr at 773, 883 and 985° C. for periods of 75 min. Cubic law of oxidation is valid at 770 and 880, and for beginning of oxidation at 985° C. Linear law is valid at 985° C., except at beginning of oxidation. Study of diffusion of oxygen to interior of metal from oxide film. 19 references.—RML. 19506

6.3.19, 3.8.3, 3.6.5, 2.3.5

Some Potentiostatic Studies on Zinc. I. Sanghi and M. Fleischmann. Electrochim. Acta, **1,** Nos. 2/3, 161-176 (1959) July.

The over-all passivation phenomenon in the case of Zn is very rapid and cannot be fully studied by galvanostatic techniques alone. The constant overvoltage technique has thus been applied to Zn. The d.c. amplifier used had a gain of 100,000 without feed-back. Current/potential curves were obtained in 6N, N, 0.1 N and 0.01 N KOH and zincate solutions for the range of —1.3 to about +2.0 V with respect to Hg/HgO/KOH as reference electrode. It has been found that in the first truly active region the main electrode reaction is the formation of Zn ions; after passivation, it changes to gas evolution.—BTR. 19504

6.3.20, 3.7.2, 4.6.2

Effect of Palladium on the Corrosion of Zirconium in Hot Water. (In German.) Hans-Walter Schleicher. Z. Metallkunde, **50,** 687-690 (1959) December.

Zr-Pd alloys with 0.1-10 percent Pd are exposed to water or steam at 360-480° C. at a pressure of 1 or 200 atmospheres. For comparison, samples of pure Zr and samples of Zr in contact with Pd or Zr_2Pd were subjected to the same treatment. The protective effect of Pd on Zr present as an alloying element or in the environment, is understood as anodic protection. 16 references.—RML. 19502

6.3.20, 8.10, 2

Zirconium and Its Alloys and Hafnium. Usine nouvelle, **1959,** Numéro spécial, 77, 79-81, 83-85, 87, 89.

The occurrence, extraction, and refining of zirconium are surveyed, together with the properties and applications of zirconium and its alloys. Particular attention is paid to the separation of zirconium and hafnium. The comparative corrosion-resistances of zirconium, titanium, tantalum and stainless steel to a number of media are tabulated. Hafnium is dealt with briefly. 19 references.—MA. 19538

6.3.6, 3.8.4

Internal Oxidation of Copper-Aluminum Alloys. D. L. Wood. Trans. AIME (Metallurgical Society), **215,** 925-932 (1959) Dec.

Investigation of aluminum oxide particle dispersions, mechanical properties and recrystallization characteristics of internally oxidized copper-aluminum alloys. 6 references.—RML. 19592

6.3.6

A Substitute for Silicon Bronze—Its Fabrication and Properties. R. E. Martin. Paper before Wire Assoc., Annual Convention, Cleveland, Oct. 13, 1959. Wire and Wire Products, **34,** No. 10, 1343-1344, 1414 (1959) Oct.

Experiments indicate that silicon brass within range of 89.0-91.0 copper, 0.8-1.5 silicon, remainder zinc, would make good alternate for silicon bronze. This is based on good corrosion resistance of this alloy as well as its casting and working properties. Silicon brass shows no sign of dezincification (tested in $CuCl_2$) and is resistant to stress-corrosion (tested in $HgNO_3 \cdot 2\,H_2O$ and in NH_4OH). Graph shows effect of silicon content and cold working on tensile strength of Silcalloy silicon brass. Tables compare tensile and yield strengths for silicon brass and silicon bronze wires.—INCO. 19331

6.3.5, 6.3.13, 3.4.6

The Oxidation of Columbium-Base and Tantalum-Base Alloys. A. E. Michael. pp. 487-507 of "Reactive Metals," Metallurgical Society Conferences, Vol. 2, 1959. Interscience Publishers, Inc., New York 1, N. Y.

Binary, ternary and quaternary niobium-base and tantalum-base alloys exposed to flowing air at 2000 F. Data for resistance to oxygen scaling and effects of oxygen on mechanical properties. 26 references.—RML. 19338

6.3.6, 3.7.2

Influence of Impurities on the Properties of Brasses. (In French.) Pierre-Julien le Thomas and Dominique Arnaud. Fonderie, No. 162, 323-325 (1959).

The effects of lead, tin, iron, phosphorus, antimony, magnesium, arsenic, nickel, aluminum, silicon, manganese, cadmium and cobalt on the properties of 30-50 percent zinc brasses are briefly reviewed. Lead improves machinability; manganese increases corrosion-resistance, while iron is injurious to it; mechanical properties are improved by nickel and cobalt but lowered by phosphorus, antimony, magnesium and silicon. 23 references.—MA. 19282

6.3.6, 4.3.2, 5.8.1

Research on the Behaviour of Copper and Brass in Diluted Mineral Acids in the Presence and Absence of Inhibitors. (In German.) M. Laćan, T. Marković and Lj. Rubinić. Werkstoffe u. Korrosion, **10,** No. 12 (Suppl.), 767-769 (1959) December.

It is shown how the corrosion-chemical behavior of copper and brass Ms. 70 can be represented by i_o-pH diagrams. The object of the experiment was the investigation of the influence of KH_2PO_4, $SnCl_2$, naphthoic acid, co-linoleate and oleic acid on the corrosion and the corrosion rate of copper and brass Ms 70. In both cases, co-linoleate and $SnCl_2$ act as inhibitors. 19281

6.3.17, 6.3.21

Corrosion of Manganese and Uranium. (In French.) J. S. Llewelyn Leach. Mém. Sci. Rev. Mét., **56,** 675-680 (1959) Dec.

Differences in corrosion rate of manganese depend on composition of attacking liquid, allotropic structure of the manganese alloy and its hydrogen content. Similarity of manganese and uranium is basis for interpretation of "breakaway" corrosion in uranium and aluminum caused by hydrogen in the solution. 14 references.—RML. 19286

6.3.5, 3.7.3, 3.7.4

Observations on the Niobium-Hydrogen System. H. W. Paxton, J. M. Sheehan and W. J. Babyak. Trans. Met. Soc., Amer. Inst. Min. Met. Eng., **215,** No. 4, 725-727 (1959).

X-ray and metallographic studies of single crystals of niobium annealed at 300, 600 and 900 C in purified hydrogen for 50 hours, cooled to room temperature in 5 minutes, and then annealed at 600 C for 1 hour, suggest that many criteria of martensitic phase transformations are satisfied and that the martensitic plates observed are the "hydride" phase identified by previous workers. The mechanics of the transformation have some practical implications, e.g. the method of formation of the plates could markedly influence the behavior of niobium-containing material in high-pressure water. 11 references.—MA. 19361

6.4 Non-Ferrous Metals and Alloys—Light

6.4.2

Aluminium-Magnesium Alloys Move Into Structural Field. Steel, **144,** No. 15, 106-109 (1959) April 13.

Since aluminium-magnesium alloys have high strength, and are welded almost as readily as low carbon steels, they are well suited for use in the chemical, power, transportation, marine, structural fields and in new uses. Corrosion resistance of these alloys is good. These end uses include large storage tanks for corrosive chemicals; low temperature applications in handling liquid methane, ethane, hydrogen, oxygen, nitrogen and helium; in handling liquid propellants for guided missiles, such as oxygen, hydrogen peroxide and red fuming nitric acid; tank cars for handling a variety of chemicals; for storing and distributing high purity water and condensate in power plants and atomic energy installations; semi-trailer dump bodies; ships' superstructures (such as Sunrip), and small boats, including an all welded personnel boat for service in Lake Maracaibo, Venezuela; pipelines, drilling templates, and numerous oil well structures; cranes and bridges. A table showing many alloys in the aluminium-magnesium class, together with their compositions, and the commercial forms in which each is available is presented. —ALL. 19517

6.4.2, 3.5.8, 3.4.8

The Influence of Cations on the Stress Corrosion of Aluminum Alloys. H. Spindler. Paper Presented at the Meeting of the German Metallurgical Society, Essen, Germany, September, 1958. Galvanotechnik, **50,** 211-213 (1959) April 15.

The stress corrosion behavior of Al-7 percent Mg and Al-Cu-Mg-Mn alloys in various aqueous solutions of metal chlorides was investigated under comparable conditions. It is pointed out that the quality of the distilled water used is a factor of considerable importance. Very small quantities of heavy metal ions (water distilled in a Cu apparatus) produce quite pronounced effects. None of the Al-Cu-Mg samples exhibited cracks, although, when tested in artificial seawater using the alternate immersion method, they have shown high sensitivity. In Al-7 percent Mg alloys chloride solutions of Cu, Hg, Fe, Co, Ni, Sn, Pb and Cd produced stress corrosion effects. With longer annealing periods at 150 C the number of metal chlorides capable of triggering stress corrosion, increases. The coupling of such "triggering" cations with anions other than chloride ion, reduces their number and leads to considerably larger endurances. The phenomenon is attributed to the greater power of penetration of chloride ions into the aluminum oxide film.—ALL. 19465

6.4.2, 3.7.3, 4.3.2, 4.4.2

An Investigation of the Corrosion-Resistance of Welded Joints in Aluminium. (In Russian.) I. I. Skvortsov. Svarochnoe Proizvodstvo (Welding Production), **32,** No. 11, 18-19 (1959). English Translation of Journal Available from British Welding Res. Assoc., 29 Park Crescent, London, W. 1, England.

Commercial-grade and high-purity aluminum were tested. Welds were immersed in cold and boiling 97 percent acetic and 98 percent nitric acids. The submerged arc-welded joints had corrosion-resistance equal to that of the base metal. In cold acetic acid pitting occurred, but other conditions produced uniform corrosion. Results from automatic submerged arc-welding were equally as good as with gas and manual-arc welding.—MA. 19486

6.4.2, 3.7.3, 4.3.2, 2.3.2

Corrosion Testing of Aluminum Weldments in Nitric Acid. (In Russian.) D. M. Rabkin, N. A. Langer, L. N. Yagupol'skaya and V. D. Pokhodenko. Avtomat. Svarka (Automatic Welding), No. 8, 49-56 (1959).

To work out acceptable accelerated method of testing corrosion of welded joints of aluminum in nitric acid, preparation of sample surfaces and other conditions have been defined.—RML. 19402

6.4.4, 3.5.3, 4.6.5, 3.5.11

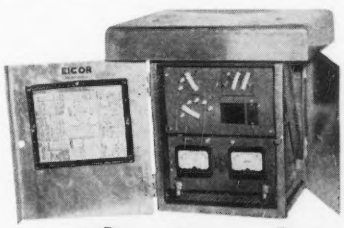
Erosion of Magnesium. Albert H. Peters. E. I. Du Pont de Nemours and Co. U. S. Atomic Energy Commission Pubn., DP-377, June, 1959, 12 pp. Available from Office of Technical Services, Washington, D. C.

Specimens of a magnesium alloy containing 8 wt. percent aluminum were eroded at a rate of 0.1 in/yr when exposed at 40 C to deionized water flowing at a velocity of 20 ft/sec. The rate of erosion was several times higher for specimens with lower concentrations of aluminum. (auth)—NSA. 19364

6.4.2, 4.6.1, 8.4.5

Aluminum Alloys for Water-Cooled Power Reactors. E. C. W. Perryman. J. Inst. Metals, **88,** Pt. 2, 62-73 (1959) Oct.

Corrosion properties of Al-Ni-Fe alloys in both static and dynamic high-temperature water (260, 300 and 350 C) are described. Corrosion-resistance in high-temperature water flowing at 20 ft/sec is about 8 times that in a static system, and there is little effect of alloy composition under dynamic conditions. Under flowing conditions, corrosion rate is very dependent on amount of Al surface within dynamic system and this is thought to be due to saturating the water with Al oxide. Under dynamic conditions, lowest corrosion rate observed is about 8×10^{-3} in/yr, but in oxide film formed on samples in static water will reduce corrosion rate to about 2×10^{-3} in/yr. Effect of inhibitors is discussed, and also that of heat flux. Results are given for both short- and long-term mechanical properties. Properties of these alloys are discussed in relation to water-cooled power reactors, and it is shown that at present stage of de-



The Completely Engineered Cathodic Protection Rectifier

- EICOR'S "complete unit" manufacturing facilities insure: QUALITY CONTROL... ECONOMICAL DESIGN ...PROMPT DELIVERY.
- Field tested EICOR RECTIFIERS are available up to 5,000 watts. Convection air cooled or oil immersed. Single or three phase full wave.
- Standard or special input voltages. All cases are 11 gauge steel (SMALL ARMS PROOF.)
- Case is designed for minimum maintenance in the field and easy accessibility to all components.
- A new approach in cathodic protection rectifier design and manufacture.
- Manufactured in our own plant, under one roof, to the most exacting specifications and rigid controls.
- Write or phone today your nearest representative for descriptive literature and "The Eicor Story."

EICOR Manufacturers of Electrical Equipment for over 25 years.

Chicago 39, Illinois
4059 West North Ave.
Phone HUmbolt 6-2060

Houston (24) Texas
P.O. Box 19333
Phone JA 2-6643
HO 8-7154

Dallas (9) Texas
4807 Elsby Ave.
FLeetwood 2-6085

FACTORY:
517 West Walnut Street
Oglesby, Illinois

159a

velopment they are not competitive with Zircaloy for fuel sheathing. Alloys chosen for most intensive study were 155 (0.5 Ni-0.5 Fe-0.2 Si) and 157 (2.0 Ni-0.5 Fe-0.2 Si). Photos, numerous graphs, tables and photomicrographs. 28 references.—INCO. 19369

6.4.2, 4.4.5

Reaction of Aluminum and Carbon Tetrachloride. Pt. I. J. D. Minford, M. H. Brown and R. H. Brown. J. Electrochem. Soc., **106,** No. 3, 185-191 (1959).

Many aluminum alloys are corroded severely by boiling carbon tetrachloride but the attack decreases with increasing magnesium content and with decreasing temperature; attack at room temperature is negligible. Two of the reaction products are hexachloroethane and aluminum chloride and the addition of the latter accelerates the reaction. It is suggested that the acceleration occurs through formation of a complex with aluminum chloride and carbon tetrachloride. Addition of acid anhydrides, amines, esters, and other groups of compounds which can complex with aluminum chloride retard the reaction. 15 references.—MA. 19325

6.4.2, 4.6.1

Corrosion of Aluminum-Uranium Alloys in High-Temperature Water. W. E. Ruther and J. E. Draley. Argonne National Lab. U. S. Atomic Energy Commission Pubn., ANL-6053, November, 1959, 9 pp. Available from Office of Technical Services, Washington, D. C.

Sixty-day corrosion tests were performed in water at 290° C with unirradiated aluminum-uranium alloys containing 2 wt. percent nickel and ½ wt. percent iron, with several uranium contents from 15 wt. percent to 53 wt. percent. The maximum metal penetration rate (4 mils per year by extrapolation) of these alloys was no more than twice that of X8001 aluminum cladding alloy at the same temperature. Preliminary testing in water at 350° C indicated good corrosion resistance for this alloy system up to a maximum of 80 wt. percent uranium. (auth.)—NSA. 19509

6.4.2, 4.6.2, 3.2.2, 3.2.3, 3.5.9

The Corrosion of Aluminium and Its Alloys in High-Pressure Steam. N. J. M. Wilkins and J. N. Wanklyn. J. Inst. Metals, **88,** No. 3, 134-140 (1959-1960).

An aluminum alloy, Aereal 1 (2.5 wt. percent Ni) was exposed to steam at 270-500 C for periods up to one week. Three distinct types of corrosion were observed: 1) uniform film growth; 2) penetrating attack, starting from points and spreading over the whole surface, the final product being a fine grey powder; 3) "growth" of the specimen. Up to 350 C, uniform corrosion was the rule, and rapid failure was rare. At 325 C and constant pressure, uniform corrosion followed a parabolic law, the rate constant having a high-pressure-dependence (approx. $\propto p^4$). Tests suggested that, at a given pressure, the actual corrosion decreased with increasing temperature between 270 and 350 C, and also that the temperature-dependence was less at both 270 and 350 C than at 325 C. At 400 C and above, a high proportion of specimens showed penetrating attack. Growth was found only at 500 C. SAP samples were also tested. At 350 C and below their resistance was very poor. At 500 C, however, SAP seemed notably less liable than Aereal 1 to penetrating attack. SAP containing 1 wt. percent nickel was also tested, and appears to combine the good resistance of the nickel alloy at lower temperature (~300 C) with the resistance of ordinary SAP to penetrating attack at 500 C. (auth)—MA. 19599

6.4.4, 8.9.2

Unprotected Magnesium Performs Well in Automotive Parts. M. A. Schertel. Dow Chemical Co. Automotive Inds., **121,** No. 4, 60-61, 116 (1959) August 15.

Service experience has shown that Mg can be used for many functional automotive parts without protective finishes. Twenty-two engine, transmission and running gear parts in which Mg has been used successfully are listed. Since salt-spray tests are comparative only, success of Mg prototype parts in road tests has proved to be only reliable indicator of how metal performs in service. To illustrate good corrosion resistance of Mg in automotive applications, Dow Chemical Co. recently made a spot check of a variety of Mg parts on cars in actual service. Photos of several of these parts are shown. Corrosion-inhibiting oil film formed on working parts of automobile contributed to their excellent condition.—INCO. 19501

6.5 Metals—Multiple or Combined

6.5, 8.1.2

The Resistance of Non-Ferrous Metals to Corrosion in Buildings. F. E. Jones. *Chemistry & Industry,* No. 31, 1050-1063 (1957) Aug. 3.

A study of corrosion of lead, copper, zinc and aluminum as used in construction applications.—BTR.

6.5, 4.3.2

High Performance Materials, Alloys and Reactive Metals. F. S. Badger. Haynes Stellite Co. Ind. Eng. Chem., **50,** 1608-1611 (1958) November.

Corrosion tests were made of molybdenum, stainless steels, Hastelloy alloys tantalum, zirconium, tungsten, and niobium under various conditions in widely used mineral acids, such as nitric, hydrochloric, phosphoric, and sulfuric. The results are tabulated and graphically represented. In addition, some comparisons of oxidation rates of metals and alloys are presented. The presentation is intended as a guide for selecting alloys and metals for service under corrosive conditions in the chemical industry.—NSA. 18116

6.5, 3.5.9, 3.4.6

The Properties of Eleven Less Common Metals. B. A. Rogers. American Society for Metals Conf. on Metals for Supersonic Aircraft and Missiles, **1958,** 261-314; Appendix, 365-368. Available from the Society, 7301 Euclid Ave., Cleveland 3, Ohio.

Chromium, hafnium, iridium, molybdenum, niobium, osmium, rhenium, tantalum, vanadium, tungsten and zirconium are considered. Fabrication, mechanical and corrosion properties are described and illustrated. The effects of temperature and impurity gases (oxygen, nitrogen and hydrogen) on the properties are discussed. Zirconium, vanadium and chromium possess the lowest d but under some conditions their strength:weight ratio is less than that of tungsten. Chromium has a high modulus of elasticity and good resistance to hot corrosive gases, but is brittle at room temperature. Molybdenum, tungsten and rhenium all have good strength at high temperatures but oxidize readily. Molybdenum and tungsten are also brittle at room temperature. Iridium is the more promising of the two precious metals, having good resistance to atmospheric attack up to 800 C and a very high modulus of elasticity at room temperature. However, iridium is difficult to fabricate at any temperature. In an Appendix some room temperature physical and mechanical properties of the metals are tabulated and discussed. 128 references.—MA. 18939

6.6 Non-Metallic Materials

6.6.5, 4.6.1

On the Causes and Progress of Aggression Due to the Attack of Corrosive Waters on Cement Mortar and Concrete. First Communication. (In German.) F. W. Meier-Grolman. Werkstoffe u. Korrosion, **10,** No. 12 (Suppl.), 739-760 (1959) Dec.

This First Communication presents a comparative synopsis of present knowledge and experience of the causes and progress of agression with special regard to recent developments, during the attack of corrosive waters on cement mortar and concrete, inasmuch as these are relevant to the casual relationship between cause and effect and to the processes during concrete corrosion in the mortar bed. This communication also deals with the different measures to enhance the corrosion resistance in concrete practice, and the influence of these measures on the concrete properties. 19313

6.6.6, 3.7.2

Alloying Boride Systems with Silicon. (In Russian.) K. I. Portnoi, G. V. Samsonov and K. I. Frolova. Izvest. Akad. Nauk SSSR, Otdel Tekh. Nauk Met. i Toplivo, No. 2, 117-121 (1959) March-April. Translation available from Henry Brutcher, Technical Translations, P. O. Box 157, Altadena, Calif.

A method is suggested for improving the heat resistance of boride systems by alloying them with silicon or high-melting metallic silicides. It is shown that relatively small additions of elementary silicon or silicides are sufficient. The admixture of silicides improves the oxidation resistance of the material, while silicon improves its sintering resistance. 4 figures.—NSA. 19415

6.6.6, 3.7.4

Alloys of the Boron Carbide-Molybdenum Disilicide System. (In Ukrainian.) G. V. Samsonov, V. S. Sinelnikova and P. S. Kislyi. Dopovidi Akad. Nauk Ukr. R. S. R., No. 8, 866-868 (1959).

Properties of the boron carbide-molybdenum disilicide alloys were investigated by the methods of metallography, X-ray patterns, conductivity, and thermal emf. Formation of the quadripartite phase of variable constitution, like Nowotny phases $Mo_x(B_1C_1,Si)_y$, is found, with a very wide homogeneous region across which (from 10 to 50 mole percent $MoSi_2$ in alloys with boron carbide) electrical resistivity increases and thermal emf decreases, in accordance with the degree of defectiveness of the lattice of this phase. The quadripartite compound is shown to be highly resistant against oxidation. (auth).—NSA. 19503

6.6.6, 8.8.5

The Preparation and Properties of Three Refractory Beryllides. Walston Chubb and Ronald F. Dickerson. Bat-

telle Memorial Inst. U. S. Atomic Energy Commission Pubn., BMI-1327, March 3, 1959, 20 pp. Available from Office of Technical Services, Washington, D. C.

The beryllium compounds $NbBe_{12}$, YBe_{13} and $ZrBe_{12}$ were prepared by arc melting. Some beryllium was lost in this operation but sound ingots were obtained. The hardness, density, metallographic structure, X-ray structure and oxidation resistance in air of each ingot were determined. The zirconium compound apparently had a tetragonal structure corresponding to $ZrBe_{12}$ and a hardness of 790 Knoop and a density of 2.94 g/cm³. The yttrium compound had a cubic structure corresponding to YBe_{13} and a hardness of 870 Knoop and a density of 2.57 g/cm³. The niobium compound had a tetragonal structure corresponding to $NbBe_{12}$ and a hardness of 1100 Knoop and a density of 3.14 g/cm³. The zirconium alloy was most difficult to prepare and crumbled at 700 C during oxidation testing. The niobium and yttrium alloys were both relatively easy to prepare and both were highly resistant to oxidation at 1300 C. The niobium alloy had the most satisfactory behavior in all respects and appears most promising for further development. (auth)—NSA. 19699

6.6.6

Chromium Carbide as a Basis for Hard Metals Having Special Properties. (In Russian.) V. V. Grigor'eva, V. N. Klimenko and T. Ya. Kosolapova. Voprosy Poroshkovoy Metallurgii i Prochnosti Materialov, **1958,** 79-89. Translation Available from Henry Brutcher, Technical Translations, P. O. Box 157, Altadena, Calif.

Properties of known chromium carbides and how they compare with those of other metal carbides. Most favorable conditions for production of Cr_3C_2; structure; nickel-bonded chromium carbide. Mechanical properties of Cr_3C_2; corrosion resistance; oxidation resistance compared with that of stainless steel at 950 C.—TT. 19185

6.7 Duplex Materials

6.7.2, 7.1, 3.5.9

Experimental Evaluation of Cermet Turbine Stator Blades for Use at Elevated Gas-Temperatures. Patrick T. Chiarito and James R. Johnston, U. S. National Aeronautics Space Administration Memo., 2-13-59E, 1959, 25 pp.

K162B cermet (TiC 64, Ti (Nb, Ta)C 6, Ni 25, Mo 5 percent) was engine-tested at 2000 F (1095 C.) Loosely mounted blades survived 52 hours. Distortion of the trailing edges of some blades was observed, indicating substantial ductility at service temperature. A tightly mounted blade fractured. Oxidation occurred, creating an impervious, adherent coating.—MA. 19689

6.7.2

Development and Properties of Uranium Monocarbide Cermets. Final Report. Illinois Inst. of Technology for Westinghouse Electric Corp., U. S. Atomic Energy Commission Pubn., AECD-4289, September 17, 1956 (Declassified August 17, 1959), 66 pp. Available from Office of Technical Services, Washington, D. C.

Uranium monocarbide-Zircaloy-2 alloy cermets were developed and tested for chemical and physical properties. It was demonstrated that pure uranium monocarbide can be prepared by vacuum arc melting techniques. Following melting, the comminution, hot pressing and corrosion behavior of dense monocarbide has been studied. The preparation of uranium monocarbide-Zircaloy-2 cermet bodies was investigated by means of hot pressing, cold pressing and sintering, warm pressing, extrusion and hot rolling. The corrosion resistance of the cermets was related to such variables as composition, preparation technique and powder size. Thirty percent uranium monocarbide, 70 per cent Zircaloy-2 cermets withstood corrosion tests in 680 F water. Cermets having above 30 wt per cent uranium monocarbide were not corrosion resistant. (auth)—NSA. 19231

6.7.2

Recent Advances in Cermets. Robert Steinitz. Jet Propulsion, **28,** No. 1, 15, 68-70 (1958).

A review, covering competition of cermets with superalloys and refractory pure metals, use as bearing materials for operation at 800-1500 F (425-815 C), microstructure and production methods. 18 references.—MA. 19002

8. INDUSTRIES

8.4 Group 4

8.4.3, 4.3.2, 4.4.8, 4.4.9, 5.8.4

Corrosion Control in Petroleum Refineries Processing Western Canadian Crude Oils. C. L. Easton. A Paper Presented at a Meeting of the Canadian Region (Eastern Division), Montreal, Quebec, Jan. 12-14, 1959. Corrosion, **16,** No. 6, 275t-280t (1960) June. See also: Oil in Canada, **12,** No. 27, 76-86 (1960) May 2.

Corrosion problems encountered in petroleum refineries processing Western Canadian crude oils, and the methods used to overcome them, are outlined. Hydrogen sulfide and other sulfur compounds, together with hydrochloric acid formed from chlorides in the water associated with the crude oils, are the chief factors in the corrosion of crude distillation units. Preventive measures include desalting, use of alloy materials, neutralization of the hydrochloric acid, and the use of film forming organic inhibitors.

Corrosion in catalytic cracking light ends equipment is attributed to nitrogen compounds and cyanides. Water washing to reduce cyanide concentration, the use of film-forming inhibitors, and the use of corrosion resistant materials are used with success to reduce the severity of the attack.

In catalytic reforming units, the problem of high temperature hydrogen sulfide corrosion is overcome by removing the sulfur in a feed preparation unit. Embrittlement of carbon steel by high temperature, high pressure hydrogen is a potential hazard in reforming units, but can be prevented by the use of refractory linings or low alloy steels containing chromium and molybdenum. Under certain conditions, strong acids are formed in these units creating further corrosion problems at temperatures below the dew point. 19708

8.4.5, 2.3.9

Metallographic Examination of Components and Coupons from HRP In-Pile Loop L-2-21—Part I. A. E. Richt. Oak Ridge National Lab. U. S. Atomic Energy Commission Pubn., CF-58-9-15, September 2, 1958, 17 pp. Available from Office of Technical Services, Washington, D. C.

Metallographic examinations of representative corrosion specimens and reactor component sections from HRP in-pile loop are reported. The loop was operated for a total of 889 hrs. at 280 C in beam hole HB-2 for the LITR, during which time the reactor logged 1710 Mwh of operation. The results are discussed and tabulated. Photographs are also included.—NSA. 19434

8.4.5, 6.3.17

Power Reactor Program. Progress Report to E. I. du Pont de Nemours and Co. for the Period March 19, 1958 through April 11, 1958. A. R. Gilman, S. Isserow, R. G. Jenkins, D. F. Kaufman, J. L. Klein, S. R. Maloof, W. B.

LET *Coreco* WORK FOR YOU 24 HOURS A DAY TO PROTECT YOUR OFFSHORE EQUIPMENT AGAINST COSTLY CORROSION . . .

Two-fisted Coreco protection pays for itself many times. Whether your problem is better solved by rectifiers or magnesium anodes, our engineers have the knowledge to determine lowest overall installation and operating costs. It costs you nothing to check with Coreco engineers.

Coreco

Write or phone today for COSTS • SURVEYS • DESIGNS INSTALLATIONS • MATERIALS

Corrosion Rectifying Co., Inc.

5310 ASHBROOK • MO 7-6659
HOUSTON 36, TEXAS

Nowak and A. M. White. Nuclear Metals, Inc. U. S. Atomic Energy Commission Pubn., NMI-4361, April 8, 1958, 44 pp. Available from Office of Technical Services, Washington, D. C.

The extrusion, etching, polishing, heat treatment and testing of U-2 wt. percent zirconium (Zircaloy-2 clad) fuel tubes are described. Consistent and meaningful quantitative data were obtained on the progress of core corrosion through artificial cladding defects. Curves of hydrogen evolution versus time, providing corrosion data versis time, were obtained on both as-extruded and heat-treated specimens at 277 C.—NSA. 19737

8.4.3, 5.8.2

The Use of Corrosion Inhibitors in the Petroleum Industry. (In French.) Leo Cavallaro. Corrosion et Anticorrosion, **7**, 417-433 (1959) Dec.

Comprehensive survey of corrosion problems in extraction, refining, storage and transportation of petroleum. Detailed treatment of passivating, film-forming and vapor phase inhibitors and their specific applications. Wettability of surfaces to be protected, solubility and stability of inhibitors, influence of temperature, pH and rate of fluid flow in relation to effectiveness of inhibiting substances. 41 references.—RML. 19650

8.4.5

Fuel Elements for Gas Cooled Reactors. (In German.) M. Becker. Atomkernenergie, **4**, 244-247 (1959) June.

The high gas temperatures planned for future gas-cooled power reactors make the development of new types of fuels necessary. Only a slight increase in temperature would be expected in the transition from uranium fuel rods to uranium tubes or plates. The transition to ceramic fuels offers the possibility of a greater temperature increase. The canning materials must have sufficient high-temperature strength and corrosion resistance. The metals and ceramic materials with these properties are discussed. For the highest temperatures, graphite is probably most suitable. (auth) NSA. 19681

8.4.5, 4.6.5, 6.4.2, 3.2.2, 5.9.2

Project Aquarium: Laboratory and Field Corrosion Tests for the Geneva Conference Reactor. James L. English, Arnold R. Olsen and E. G. Bohlmann. Oak Ridge National Lab. U. S. Atomic Energy Commisson Pubn., ORNL-2716, July 9, 1959, 62 pp. Available from Office of Technical Services, Washington, D. C.

The unfavorable corrosion behavior of a group of Geneva Conference Reactor fuel elements during criticality tests in the Bulk Shielding Facility prompted a laboratory and field investigation to determine the cause or causes for the observed behavior. The laboratory tests were conducted in distilled water with source materials of 1100 Al used in the fabrication of Geneva and other types of fuel elements. The field tests were run in demineralized cooling water at the Bulk Shielding Facility with dimensionally rejected Geneva elements. Relatively brief exposure periods in the laboratory tests resulted in an average corrosion rate of 0.6 mpy for 1100 Al; the rate decreased with time. In one case, severe pitting attack was traced to iron contamination on the surface of the Al. An extended pickling time with sulfuric-chromic acid solution to remove the contamination was effective in eliminating the attack. There was an indication that the nitric-hydrofluoric acid pickling solution used during the fabrication of Geneva elements instigated pitting attack on Al. The Si-Al alloy used to braze the fuel plates to the Al side plates was found to be highly susceptible to pitting attack in distilled water. In the field tests, during exposure periods of several months in demineralized cooling water, numerous pits penetrating 50 percent of the 17.5-milthick aluminum cladding on Geneva elements were observed; in one case, a 62 percent penetration occurred in 45 days. Some evidence was obtained that the effect of water flow was to minimize pitting attack and staining on an irradiated fuel element exposed in demineralized water. (auth)—NSA. 19758

8.4.5, 4.7, 6.2.5

Effect of 1200 F Sodium on Austenitic and Ferritic Steels. Bi-monthly Progress Report No. 1 for July and August 1959 on Thermal Shock, Nitriding, Stressed Corrosion, Unstressed Corrosion. J. W. Mausteller and R. C. Werner. MSA Research Corp., Callery, Pennsylvania. Contract AT(11-1)-765, September 16, 1959, 22 pp. Available from Office of Technical Services, Washington, D. C.

Completion of preliminary designs for a thermal shock loop, a corrosion loop and a nitriding loop is reported. Stressed and unstressed corrosion studies are scheduled to be carried out in the same system. A literature search was started, and various sites were contacted to avoid duplication of effort. It was found that some work has been done at 1200 F sodium temperature with various oxygen concentrations, however part of the data is contradictory. Test plans include corrosion testing of Croloy and stainless steel samples as well as similar and dissimilar welds of these materials in 1200 F sodium.—NSA. 19311

8.4.5, 6.3.10

Aircraft Reactor Experiment—Metallurgical Aspects. W. D. Manly, G. M. Adamson, Jr., J. H. Coobs, J. H. DeVan, D. A. Douglas, E. E. Hoffman and P. Patriarca. Oak Ridge National Lab. U. S. Atomic Energy Commission Pubn., ORNL-2349, Jan. 9, 1958 (Declassified October 9, 1959), 57 pp. Available from Office of Technical Services, Washington, D. C.

The selection of the proper structural material to be used in the construction of an Aircraft Reactor is influenced by a number of important requirements. The material must have an acceptable cross section, be resistant to elevated-temperature corrosion by liquid metals, air and the molten salts, and be free of temperature-gradient mass transfer. It must possess good creep properties in these environments and be free of structural changes during service. Finally, it must be easy to form and weld into relatively complicated shapes and be commercially available. Inconel was selected as the structural material for the Aircraft Reactor because it met these requirements. The experimental work performed in the fields of corrosion, creep and welding is described. Although a small amount of corrosion in the salt and some mass transfer in both sodium and salt were observed, the material performed quite satisfactorily during the lifetime of the reactor. The creep properties of Inconel were adversely affected by the various environments; however, by designing to limit the stress, successful operation of the reactor was achieved. Both the successful operation of the reactor and the relative ease with which a multitude of welded joints in the plumbing circuit was produced attested to the weldability of this alloy. (auth)—NSA. 19317

8.4.3

Corrosion in the Oil Industry. H. M. Powell. Corrosion Prevention and Control, **6**, No. 10, 46-48 (1959) Oct.

Covers corrosion problems and preventive measures in oil wells, gathering systems, long distance pipelines, storage tanks, jetties and submarine lines, tankers, refineries, and distribution arrangements. Coatings, linings and cathodic protection are considered.—INCO. 19423

8.4.3

Corrosion Testing and Corrosion Problems in Processing of Tall Oil. H. C. Templeton. Alloy Steel Products Co. J. Am. Oil Chemists' Soc., **36**, No. 3, 127-129 (1959) March.

Summarizes some of information published to date, presents new plant corrosion test data, and points up areas where empirical corrosion data are lacking or conflicting. Data in inches per year are given for tall oil recovery system (tall oil-naphtha-sulfuric acid at 200 F max.), high temperature reactor (esterification, amidization and sulfurization at 550 F max.) and base of tall oil fractionating tower (20 percent oleic-linoleic acids-60 percent rosin acids-20 percent tall oil pitch at 509 F and 65 percent fatty acids-35 percent rosin acids at 509 F). Materials tested include: Type 316, Aloyco 20, Worthite, Type 304, Type 317, Type 316-Mo, Ampco 18, C steel, Monel, nickel, Inconel, Hastelloy B, Hastelloy C, 20 nickel cast iron, Ni-Resist. High temperature reactor data were supplied by Inco. Test rod with disk specimens is shown.—INCO. 19579

8.4.5, 5.11

Chemical Engineering Unit Operations Help Solve Atomic Power Plant Problems. C. F. Stolzenbach. Consolidated Edison Co. Chem. Eng., **66**, No. 17, 123-128 (1959) August 24.

Problems encountered by chemical engineers in design of the Indian Point nuclear power plant are choice of materials of construction to resist corrosion and radioactivity, handling and disposing of hydrogen and oxygen (cooling-water-decomposition products due to radioactivity), preparation of ultra-pure feed water for the reactor coolant cycle, and handling of solid, liquid, and gaseous radioactive wastes.—NSA. 19533

8.4.5, 6.3.17, 4.6.5

A Visual Study of the Corrosion of Defected Zircaloy-2-Clad Fuel Specimens by Hot Water. Elmer F. Stephan, Paul D. Miller and Frederick W. Fink. Battelle Memorial Inst. U. S. Atomic Energy Commission Pubn., BMI-1387, October 19, 1959, 32 pp. Available from Office of Technical Services, Washington, D. C.

The failure of defected Zircaloy-2-clad uranium and uranium-2 wt. percent Zr fuel specimens in high-purity high-pressure water at 200 to 345 C was observed in a windowed autoclave. Time-lapse color motion pictures were taken to provide a record of the progressive changes ending in the complete disintegration of the core material in the specimens. Continuous measurement of the pressure increase caused by accu-

mulation of H served to monitor the progress of the reaction when clouding of the water by corrosion products made visual observation impossible. The nature of the attack at all specimens was similar: although the time at which different stages occurred varied. Following an induction period, the first evidence of attack was the slow formation of a blister in the cladding area surrounding the defect. Eventually, a copious evolution of hydrogen occurred at the base of the swollen area. In general, a crack could be seen in the cladding at this stage. Catastrophic failure of the specimen followed swiftly. The time required for each phase of the reaction was reduced as the temperature was raised. Initial swelling occurred after about 24 minutes at 345 C but only after 8 hours at 200 C. Diffusion-treated uranium-2 wt. percent zirconium-cored specimens were most resistant to attack. specimens with beta-treated water-quenched natural-uranium cores were least resistant. (auth)—NSA. 19535

8.4.5, 6.3.10

Inconel as a Structural Material for a High-Temperature Fused-Salt Reactor. J. R. Weir, Jr., D. A. Douglas and W. D. Manly. Oak Ridge National Lab. U. S. Atomic Energy Commission Pubn., ORNL-2264, June 18, 1957 (Declassified July 30, 1959), 78 pp. Available from Office of Technical Services, Washington 25, D. C.

The use of a circulating-fuel type of nuclear reactor as an energy source in aircraft propulsion system imposed upon the structural material metallurgical restrictions which limit the applicability of certain types of alloys. The general factors which must be considered in the selection of an alloy for this application are corrosion resistance, fabricability, nuclear properties, radiation damage, and elevated-temperature strength. The importance of each of these topics is pointed out, and it is shown that the selection of Inconel as a structural material was based on these criteria. (auth) —NSA. 19543

8.4.3, 3.2.3, 6.2.5

Contribution to the Study of Corrosion of a Semi-Stainless Steel by the Effluent at the Lacq Natural Gas Field. (In French.) J. A. Ternisien, A. Servasier, S. Barbezat and M. Bonnet-Gros. Compt. rend., **249**, 1655-1657 (1959) Oct. 28.

Corrosion film formed on semi-stainless steel pipe in hydrogen sulfide environment consists of friable outer layer and compact inner layer composed of pyrite and pyrrhotine. Inner layer retards corrosion process for a time.—RML. 19561

8.4.3, 3.2.2, 6.2.1, 4.3.2

Sulfide Scaling Under Hydrorefining Conditions. W. H. Sharp and E. W. Haycock. Paper before Am. Petroleum Inst., Refining Div., Midyear Mtg., New York, May 27, 1959. Oil & Gas J., **57**, Nos. 23, 25, 26, 117-120, 99-101, 102-105 (1959) June 1, 15, 22.

Corrosion rates in sulfide scaling of ferrous alloys were obtained from continuous-flow laboratory measurements under hydrorefining conditions. Laboratory unit was constructed of 2 stainless-steel reactor sections with auxiliary equipment for flow, temperature and pressure control. Test specimens were prepared in shape of cylindrical rings. Compositions of alloys are tabulated; included were Armco iron, Ferrovac E, Mo alloy steel, Cr-Mo alloy steels, and Types 410 and 304. Principal variables which determined corrosion rates of steels were H_2S partial pressure, temperature and composition of steel. Hydrocarbon exerted a depressing effect on corrosion at 700 F but not at 900 F. Organic sulfides contributed to corrosion only to extent to which H_2S was produced by their decomposition. For design purposes graphical summaries of predicted long-term corrosion were prepared. Predictions from these curves agree well with available reformer data but are conservative for mildly corrosive hydrodesulfurizer conditions. Numerous graphs and tables, photomicrographs of sulfide scale on 12 Cr steel and on pure iron, and 13 references.—INCO. 19451

8.4.5, 4.3.2, 6.2.5, 6.3.10

Power Reactor Fuels Reprocessing. Progress Report on Corrosion Studies. R. F. Maness. General Electric Co., Hanford Atomic Products Operation. U. S. Atomic Energy Commission Pubn., HW-61662, August 26, 1959, 57 pp. Available from Office of Technical Services, Washington, D. C.

Work is reported on corrosion studies of candidate materials of construction for equipment for the dissolution of Zircaloy cladding in ammonium fluoride-ammonium nitrate solutions, the total dissolution of stainless steel clad fuels in nitric acid-hydrofluoric acid solutions, and the dissolution of stainless steel cladding in dilute sulfuric acid. A single material of construction which could be used for a processing complex which would handle all of the low-enrichment fuels concerned was searched for. In the Zirflex Process (ammonium fluoride-ammonium nitrate) the 300 series stainless steels, vacuum-melted Hastelloy-F, Carpenter 20, Nio-nel, Haynes 25, and Incoloy 804 have satisfactory corrosion resistance to solutions involved in the dissolution of zirconium or Zircaloy claddings. Satisfactory dissolution rates for 304-L stainless steel cladding are obtained in the Niflex Process (1*M* nitric acid-2*M* hydrofluoric acid) solutions. The minimum practical fluoride to stainless steel ratio is about five. Among many materials studied, vacuum-melted Hastelloy-F offers the best corrosion resistance to nitric acid-hydrofluoric acid solutions encountered during decladding. In the Sulfex Process (sulfuric acid) dissolution rates for both annealed 304-L and 347 stainless steel in 3 to 3 *M* sulfuric acid are from 5 to 10 mils per hr. Vacuum-melted Hastelloy-F and Ni-o-nel show adequate corrosion resistance to the sulfuric acid-stainless steel solutions concerned in sulfuric acid decladding. During uranium or uranium dioxide core dissolution in nitric acid following decladding, some sulfate (sulfex declading) or (fluoride zirflex decladding) will be present due to incomplete rinsing or to the presence of solids (uranium tetrafluoride). Residual sulfate in the concentration range has no significant effect on the corrosion of 304-L stainless steel or vacuum-melted Hastelloy-F by nitric acid. Fluoride present will increase the corrosion potential but can be effectively complexed by aluminum. Corrosion rates of 304-L, vacuum-melted Hastelloy-F, and Ni-o-nel in nitric acid solutions are not markedly increased by low concentration (0.1 to 0.3*M*) of ferric nitrate. However, at higher concentrations (~ 1*M*) corrosion of an intergranular nature is severe.—NSA. 19296

TECHNICAL REPORTS

on

PROTECTIVE COATINGS

Other Than Pipe Line Coatings

T-6A Application Techniques, Physical Characteristics and Corrosion Resistance of Polyvinyl Chlor-Acetates. A Report of Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion. Publication 54-4. Per Copy $1.50.

T-6A Report on Rigid Polyvinyl Chloride. A Report of NACE Technical Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion. Publication 56-4. Per Copy $1.50.

T-6A Report on Epoxy Resins. A Report of NACE Technical Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion. Publication 56-5. Per Copy $1.50.

T-6A Report on Application Techniques, Physical Properties and Chemical Resistance of Chlorinated Rubber Coatings. NACE Technical Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion. (Pub. 56-6.) Per Copy, $1.50.

T-6A Vinylidene Chloride Resins. A Report of Unit Committee T-6A Prepared by Task Group T-6A-3 on Vinylidene Chloride Polymers. Publication No. 57-9. Per Copy $1.50.

T-6A Reinforced (Faced) Tank Linings. A Report by NACE Committee T-6A. Pub. 58-7. Per Copy $1.50.

T-6A Report on Thermoplastic Coal Tar Base Linings. A Report of NACE Unit Committee T-6A on Organic Coatings and Linings for Resistance to Chemical Corrosion, prepared by Task Group T-6A-16 on Coal Tar Coatings. Pub. 58-10. Per Copy $1.50.

T-6A-5 Application Techniques, Properties and Chemical Resistance of Polyethylene Coatings—A Report of NACE Task Group T-6A-5 on Polyethylene. Pub. 59-7. Per Copy $1.50.

T-6B Protective Coatings for Atmospheric Use: Their Surface Preparation and Application Physical Characteristics and Resistance. A Report of Unit Committee T-6B on Protective Coatings for Resistance to Atmospheric Corrosion. Publication No. 57-10. Per Copy $2.75.

T-6D-3 Industrial Maintenance Painting Program. A Report of NACE Technical Unit Committee T-6D on Industrial Maintenance Painting, Prepared by Task Group T-6D-3 on Paint Programs. Publication 60-8. Per copy $1.50.

TP-6G First Interim Report on Recommended Practices for Surface Preparation of Steel. (Pub. 50-5). Per Copy, $1.75.

TP-6G Second Interim Report on Surface Preparation of Steels for Organic and Other Coatings. (Pub. 53-1.) Per Copy, $3.25.

T-6K Acid Proof-Vessel Construction with Membrane and Brick Linings. A Report of NACE Technical Unit Committee T-6K on Corrosion Resistant Construction with Masonry and Allied Materials. Publication No. 57-6. Per Copy $2.75.

T-6K Acidproof Floor Construction With Membrane and Brick. A Report of NACE Technical Unit Committee T-6K on Corrosion Resistant Construction With Masonary and Allied Materials. Publication 60-1. Per copy $1.50.

Remittances must accompany all orders for literature the aggregate cost of which is less than $5. Orders of value greater than $5 will be invoiced if requested. Send orders to National Association of Corrosion Engineers, 1061 M & M Bldg., Houston, Texas. Add 65c per package to the prices given above for Book Post Registry to all addresses outside the United States, Canada and Mexico.

NATIONAL ASSOCIATION OF CORROSION ENGINEERS

1061 M & M Bldg. Houston 2, Texas

NATIONAL ASSOCIATION of CORROSION ENGINEERS

Executive Offices: 1061 M & M Bldg., Houston 2, Texas

Telephone CApitol 4-6108

Executive Secretary . . . . . T. J. HULL

Assistant Secretary and Exhibition Manager . . . . . R. W. HUFF, JR.

Technical Committee Secretary . . . . . J. F. VANDER HENST, JR.

Administrative Assistant for Regions and Sections . . . . . G. A. ROLAK

Publication Director . . . . . NORMAN E. HAMNER

Editorial Assistant . . . . . DALE MILLER

Inquiries regarding membership, and all general correspondence should be directed to the Executive Secretary at the administrative headquarters of the National Association of Corrosion Engineers at 1061 M & M Building, No. 1 Main Street, Houston 2, Texas.

•

The National Association of Corrosion Engineers is a non-profit, scientific and research association of individuals and companies concerned with corrosion or interested in it, whose objects are:

(a) To promote the prevention of corrosion, thereby curtailing economic waste and conserving natural resources.

(b) To provide forums and media through which experiences with corrosion and its prevention may be reported, discussed and published for the common good.

(c) To encourage special study and research to determine the fundamental causes of corrosion, and to develop new or improved techniques for its prevention.

(d) To correlate study and research on corrosion problems among technical associations to reduce duplication and increase efficiency.

(e) To promote standardization of terminology, techniques, equipment and design in corrosion control.

(f) To contribute to industrial and public safety by promoting the prevention of corrosion as a cause of accidents.

(g) To foster cooperation between individual operators of metallic plant and structures in the joint solution of common corrosion problems.

(h) To invite a wide diversity of memberships, thereby insuring reciprocal benefits between industries and governmental groups as well as between individuals and corporations.

It is an incorporated association without capital stock, chartered under the laws of Texas. Its affairs are governed by a Board of Directors, elected by the general membership. Officers and elected directors are nominated by a nominating committee in accordance with the articles of organization. Election is by the membership.

Advertising and Editorial Offices of CORROSION

Address all correspondence concerning advertising, circulation and editorial matters relating to CORROSION to the NACE executive offices, 1061 M & M Building, Houston 2, Texas. Inquiries concerning and orders for reprints of technical information published in CORROSION should be sent to this address also.

OFFICERS and DIRECTORS

•

OFFICERS

President . . . . . GEORGE E. BEST
Manufacturing Chemists' Assoc., Inc., Washington, D. C.

Vice President . . . . . EDWARD C. GRECO
United Gas Corporation, Shreveport, La.

Treasurer . . . . . C. G. GRIBBLE
Metal Goods Corporation, Houston, Texas

Executive Secretary . . . . . T. J. HULL
1061 M & M Bldg., Houston, Texas

DIRECTORS

Past-President

HUGH P. GODARD 1960-61
Aluminium Laboratories, Ltd., Kingston, Ont., Canada

Representing Active Membership

R. McFARLAND, JR. 1958-61
Hills-McCanna Company, Chicago, Ill.

T. J. MAITLAND 1960-63
American Telephone & Telegraph Company, New York, N. Y.

J. P. BARRETT 1959-62
Pan American Petroleum Corp., Tulsa, Okla.

E. L. SIMONS 1959-62
General Electric Co., Schenectady, N. Y.

Representing Corporate Membership

L. W. GLEEKMAN 1960-61
Wyandotte Chemicals Corporation, Wyandotte, Mich.

L. C. WASSON 1958-61
A. O. Smith Corp., Milwaukee, Wis.

J. E. RENCH 1960-63
Napko Corporation, Houston, Texas

J. S. DORSEY 1960-63
Southern California Gas Co., Los Angeles, Cal.

GUY F. WILLIAMS 1959-62
Dowell Incorporated, Tulsa, Okla.

Representing Regional Divisions

E. H. TANDY . . . . . (Western) 1958-61
Standard Oil Co. of California, El Segundo, Cal.

A. B. SMITH . . . . . (Southeast) 1960-63
Amercoat Corp., Jacksonville, Fla.

J. D. BIRD . . . . . (Northeast) 1960-63
The Dampney Company, Hyde Park, Boston, Mass.

E. F. MOORMAN . . . . . (North Central) 1959-62
International Harvester Co., Chicago, Ill.

J. A. CALDWELL . . . . . (South Central) 1959-62
Humble Oil & Refining Co., Houston, Texas

T. R. B. WATSON . . . . . (Canadian) 1959-62
Corrosion Service Limited, Toronto, Ont., Canada

Directors Ex Officio

W. F. FAIR, Chairman Regional Management Committee
Tar Products Division, Koppers, Inc., Verona, Pa.

R. A. BRANNON, Chairman Policy and Planning Committee
Humble Pipe Line Co., Houston, Texas

R. S. TRESEDER, Chairman Publications Committee
Shell Development Co., Emeryville, Cal.

T. J. MAITLAND, Chairman Technical Practices Committee
American Telephone & Telegraph Co., New York, N. Y.

A CASE
Incon
and a study
which it pr
were obtain
of the foll
15.03 perce
and 0.08 pe
samples we
condition l
fused salt b
20 percent
1:1 molar
traces of C
inert N_2 atr
of testing. T
and for va
50 days.

The type
under these
Measureme
region form
duced at a
mm per da
porous spo

★ Submitted f
° Director of
bridge, Ma
CIBA Ltd.
°° CIBA Ltd.,
°°° Supplied b
Material).

Figure 1—Ext
mersion). Obs
off of layers.

Corrosion

OFFICIAL MONTHLY PUBLICATION

National Association of Corrosion Engineers

An Association of Individuals and Organizations Concerned with Control of Corrosion

1061 M & M Building Houston 2, Texas

Vol. 16 November, 1960 No. 11

A Technical Note

Selective Corrosion of Inconel*

By R. BAKISH* and F. KERN**

Abstract

Details of a case of selective corrosion of Inconel and a tentative mechanism by which it proceeds are presented in this paper. Sheet, rod and tube samples were tested in the as-received condition by complete immersion in a fused salt bath. Tests were carried out at 800 C for tests times up to 50 days. It was found that a layer of porous sponge-like material formed on the surface. Chromium and iron were preferentially leached out of these layers. 6.3.10

Introduction

A CASE of selective corrosion of Inconel was investigated recently and a study made of the mechanism by which it proceeds. The results reported were obtained from studies on Inconel[(3)] of the following nominal composition: 15.03 percent Cr, 7.2 percent Fe, 75.4 Ni and 0.08 percent C. Sheet, rod and tube samples were tested in the as-received condition by complete immersion in a fused salt bath. The salt bath consisted of 20 percent K_2TaF_7 and 80 percent of a 1:1 molar mixture of KCl:NaCl with traces of Cl_2. This bath was kept under inert N_2 atmosphere throughout the time of testing. Tests were carried out at 800 C and for various lengths of time up to 50 days.

The type of attack which takes place under these conditions is seen in Figure 1. Measurements of the rates of attacked region formation indicate that it is produced at a rate of approximately 0.03-0.04 mm per day. This region is a layer of porous sponge-like material. The pores are located both at the grain boundaries and in the matrix of the grains and they are not interconnected (Figure 2). These pores coalesce to large macropores which eventually leads to blistering and peeling off of this porous layer, a process which further aggravates this type of destruction of Inconel.

Analysis of surfaces corroded in this manner and of porous layers peeled off from specimens show that chromium and iron are preferentially leached out. Inconel of the given nominal composition ended up as a sponge of composition 0.5 percent Cr, 2.8 percent Fe and 96.6 percent Ni.

Manly[1] et al. in a recent publication tends to present this type of corrosion almost entirely as a consequence of the well known Kirkendall effect (i.e., the ability of certain atoms to diffuse out at faster rates than others can diffuse in to fill vacancies which result from the outward diffusion). While the authors of the present article are in agreement with Manly and his co-workers, they feel that electrochemicals factors also play an important role. These factors are responsible for the initiation of this corrosion process and for the constant removal of chromium in preference to the other alloy constituents. In order to demonstrate this, determinations of the potentials of the alloying constituents under the prevailing conditions were made by measuring the emf of cells of the type $Me^o/Me^{x+}//(Cl^-/Cl_2)$ graphite, with Me = Ni,Fe,Cr in an equimolecular sodium chloride-potassium chloride melt with 10 percent potassium fluoride added.

Table 1 gives the standard potentials computed from measurements at 750 C together with the values corresponding to the free energies of formation of the pure chlorides[2] at the same temperature. Standard potentials were calculated on the basis of molality (moles solute per kilogram of solvent) with unit molality as standard state. Values obtained by Laitinen and Liu[3] from measurements in lithium chloride-potassium chloride melt at 450 C are given in the third column for comparison. The difference between

* Submitted for publication December 21, 1959.

* Director of Research, The Alloyd Corp., Cambridge, Mass. Formerly with Rare Metals Div., CIBA Ltd., Basel, Switzerland.

** CIBA Ltd., Basel, Switzerland.

(3) Supplied by Nickel Kontor, Zürich (INCO Material).

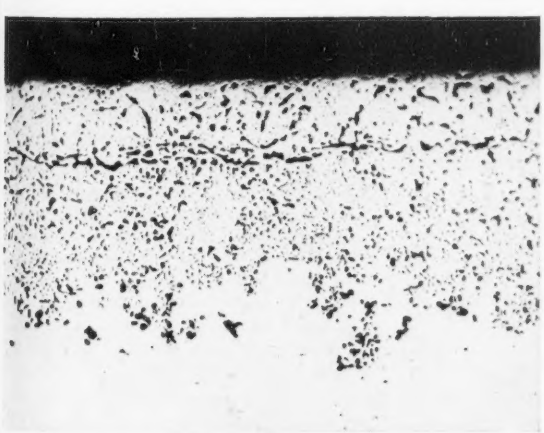


Figure 1—Extent of penetration and appearance of porous layer (18 days' immersion). Observe beginning of void coalescence leading to eventual peeling off of layers. Cross section normal to metal salt interface, unetched. Approximately 60X.

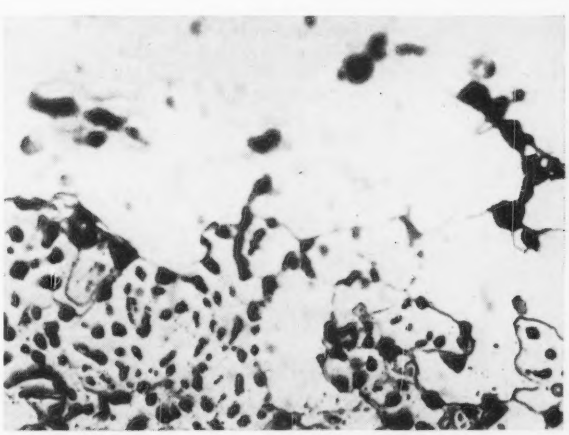


Figure 2—Lightly etched attacked region showing distribution of pores. Note pore distribution at grain boundaries and in matrices of grain. Approximately 800X.

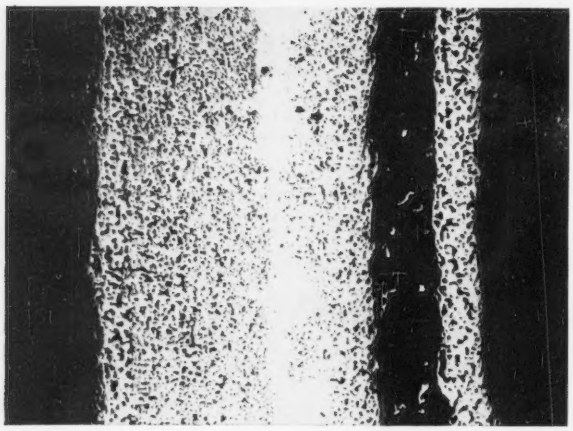


Figure 3—Extent of damage-porous layer formation and peeling off in a 1 mm wall Inconel tube completely immersed, 6 days—cross section, unetched. Peeled off layer left. Approximately 60X.

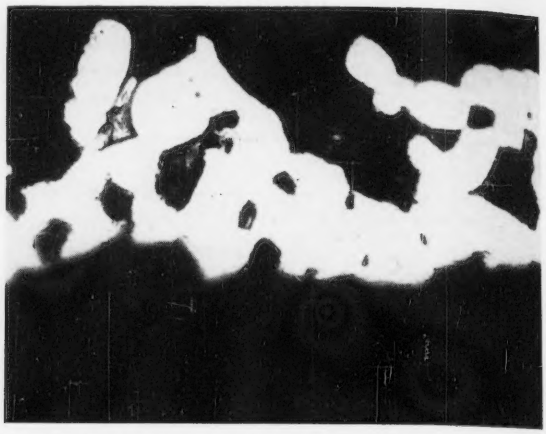


Figure 4—Peeled off layer after 30 days' immersion. Voids almost completely coalesced and diffused to surface. Approximately 400X.

TABLE 1—EMF Values of Cell $Me^{\circ}/Me^{z+}//(Cl^{-}/Cl_2)$ Graphite

Me°/Me^{z+}	E°_m Experimental Values (NaCl-KCl-KF, 750 C)	E°_m Values by Laitinen (LiCl-KCl 450 C)	Values from Free Energy Data for the Resp. Chlorides
Ni/Ni^{2+}	1.05	1.10	0.85
Fe/Fe^{2+}	1.35 ± 0.10	1.48	1.15
Cr/Cr^{2+}	1.75	1.73	1.45

measured and calculated values is ascribed to solvent action, including the complexing effect of the chloride-fluoride ions on iron, nickel and chromium. A similar explanation, namely the formation of fluoride complexes, probably accounts for the close agreement of the authors' values with Laitinen's in spite of the considerable increase in temperature.

The results show a distinct decrease in nobility in the sequence Ni, Fe, Cr demonstrating that the nobility order between the pure metals remains unchanged from that observed in aqueous electrolytes at room temperature. Considering the case of the Inconel one must bear in mind that the activities of the respective species in the alloy will deviate from unity and thus affect the stated potentials. On the basis of recently published data[4] it can be estimated that the values of Table 1 will be modified by a fraction not larger than the order of magnitude of the experimental error of the measurements. In the light of these experimental facts the mechanism described below is proposed.

Mechanism

At the given environmental conditions, which include traces of free chlorine as oxidizing agent, corrosive attack is initiated at the highly active structure sensitive sites (dislocations, subboundaries and grain boundaries). Due to the less noble potentials of chromium and iron these elements, in particular the chromium, are preferentially leached out of the alloy by galvanic action, thus producing composition gradients in the alloy.

These gradients become the driving force for diffusion. In particular chromium migrates out. Since diffusion proceeds by a vacancy mechanism and since chromium, arriving at the surface of the specimen is again dissolved in preference to the other alloy constituents due to the electrochemical factors considered, a vacancy concentration is built in the metal. At the testing temperature, 800 C, lattice vacancy mobilities are high and a coalescence of these by diffusion leads to the formation of micro and eventually macro voids.

The blistering and peeling off of layers of this sponge which aggravates this type of destruction appears then to be a consequence of this pore coalescence and the different coefficients of expansion of the Inconel and the attacked layer.

Figure 3 shows such a layer together with the "mother" tubing (6 days immersion). It is of interest to note the size of the voids in the vicinity of the sound metal indicating a much earlier stage of void coalescence. Figure 4 shows another extreme in the process of coalescence, namely a much later stage when almost all voids have coalesced or diffused out from the peeled off layer (30 days immersion). The coalescence of voids just prior to peel off is also seen in Figure 1 as a row of voids parallel to the exposed surface.

References

1. W. D. Manley et al. Atomic Energy for Peaceful Uses Conferences, Geneva, Switzerland, 15/P/1990 USA 1958.
2. L. L. Quill. The Chemistry and Metallurgy of Miscellaneous Materials—"Thermodynamics." McGraw Hill Book Company, Inc., N. Y., 1950.
3. H. A. Laitinen and C. H. Liu. *J. Am. Chem Soc*, 80, (5), 1015 (1958).
4. M. B. Panish, R. F. Newton, W. R. Grimes and F. F. Blankenship. *J. Phys. Chem*, 62, 980 (1958).

Any discussion of this article not published above will appear in June, 1961 issue.

Corrosion Problems in the Use of Dense Salt Solutions As Packer Fluids*

By C. M. HUDGINS, J. E. LANDERS and W. D. GREATHOUSE

Abstract

The corrosion characteristics were studied of dense salt solutions used as packer fluids. Among the salts considered were (1) $NaNO_3$, (2) $CaCl_2$, (3) $Ca(NO_3)_2$, (4) $ZnCl_2$, (5) $NaNO_3$-$CaCl_2$, (6) $Ca(NO_3)_2$-$CaCl_2$, and (7) $CaCl_2$-$ZnCl_2$. Only slight corrosivities were noted for the first three solutions. However, stress corrosion cracking was encountered in $NaNO_3$ solutions and in some mixtures of $NaNO_3$ and $CaCl_2$. Zinc chloride was too corrosive to obtain useful densities by itself.

Both $NaNO_3$-$CaCl_2$ and $Ca(NO_3)_2$-$CaCl_2$ exhibited severe pitting at elevated temperatures. This attack was observed to some degree on a variety of oil country materials. Penetration rates on the 1020 coupons were in excess of ¼ inch per year. The pits were very localized; polish marks were present immediately adjacent to a complete penetration.

A study of $CaCl_2$-$ZnCl_2$-H_2O mixtures yielded a system which was capable of densities up to 14 pounds per gallon without the corrosivity encountered with $ZnCl_2$ alone. Field experience has confirmed the severe corrosivity of the $CaCl_2$-$NaNO_3$ system. Two multicompletion wells with this mixture in the annulus suffered corrosion penetrations of the tubing in less than two years. 4.3.6

Introduction

THE RECENT advent of the multiple completion of oil and gas wells has brought new problems to the industry while solving past ones. The economy of several zones and allowables for one hole is fairly obvious. The development and perfection of equipment to facilitate the multiple completion will eventually make the practice the usual one where multiple sands are present. This will make many sands "economical" that could not stand alone.

The development of the multiple completion has taken place in one of the most complicated and difficult production areas in the country. The Texas-Louisiana Gulf Coast area is noted for high temperature and pressure gradients, thin layers of unconsolidated sands, and many other peculiarities. Offshore operations in the area suffer further from transportation and communication difficulties and high costs for all oil field operations.

Clear salt solutions in the tubing-casing annulus circumvent many of the problems that would be encountered in the life of a multiple completion well if a conventional mud system were used as a packer fluid under the conditions present in the Gulf Coast area (See Figure 1). These solutions are usually put into the well bore prior to any completion operations. Cleaner perforations are then obtained because no mud cake is present to be cemented in the perforation by the pressure of the perforating explosion. The plastic squeezes used to consolidate the loose sands have been successful under clear brines, while poor results have been obtained under mud.[1] The high temperature-pressure environment will solidify many mud systems used as packer fluids. This results in costly or impossible washovers. No such problem will be encountered with a clear solution.

The prime requirement for these solutions is adequate density to contain the formation pressure. Of equal importance, however, is the corrosive nature of the solution. Other factors to be considered include cost, toxicity, safety hazards, effect on other operational practices, and damage to the formation.

This paper will be concerned with the corrosion aspects of the packer solution problem. Many possible salt solution systems were considered and rejected for a variety of reasons. The ones to be considered in this report are those that showed the greatest promise. These systems are shown in Figure 2 as a function of the maximum density attainable. Each of these systems will be discussed separately with the sodium nitrate and calcium nitrate solutions being more thoroughly discussed in another paper.[2]

*Submitted for publication March 30, 1960. A paper presented at the 16th Annual Conference, National Association of Corrosion Engineers, Dallas, Texas, March 14-18, 1960.

Corrosion Studies

All of the tests were performed in a hot oil bath at 210 F on 1020 steel coupons unless otherwise noted (Figure 3). The coupons (1″ x 8″ x 1/16″) were immersed in 40 x 300 mm test tubes. The system was stagnant except for occasional agitation when the tubes were raised for visual examination. Inhibitors were added prior to the start of the test. Most of the solutions were prepared in large batches to minimize mixing uncertainties. Unless otherwise noted, commercial grade chemicals were used for all corrosion tests. Since carbon dioxide from the formation could contact the fluid (e.g., leaky packer, coupling, etc.), several test solutions were continually saturated with CO_2. The duration of each test was one month unless otherwise noted.

TABLE 1—Evaluation of Inhibitors in Saturated Calcium Chloride Solutions*

Inhibitor	Corrosion Rate, mpy
A	0.08
B	0.09
C	0.8
D	2.0
E	0.4
F	0.1
G	0.9
H	1.0
I	0.9
J	1.2
K	0.8
L	0.7
M	0.1
N	0.9
O	0.09
P	0.9

*The inhibitors were all present at a concentration of 100 ppm. Exposure was for 84 days at 212 F. The coupons used were all 1020 mild steel, 1″ x 8″ x 1/16″.

Calcium Chloride

No major corrosion was observed in $CaCl_2$ solutions as long as air was excluded.[3] Again, CO_2 accelerated the corrosion and resulted in a slight scale deposition ($CaCO_3$). Several inhibitors showed fairly good protection, although the weight losses and rates were too low for confident evaluation of the differences. The rates were almost invariably less than 1 mpy, as shown in Table 1. Addition of CO_2 increased the corrosion rate to about 2 mpy. The attack was general, and no major pitting was observed. Sodium chromate showed some protection but was relatively insoluble. Sodium nitrite apparently accelerated the attack.

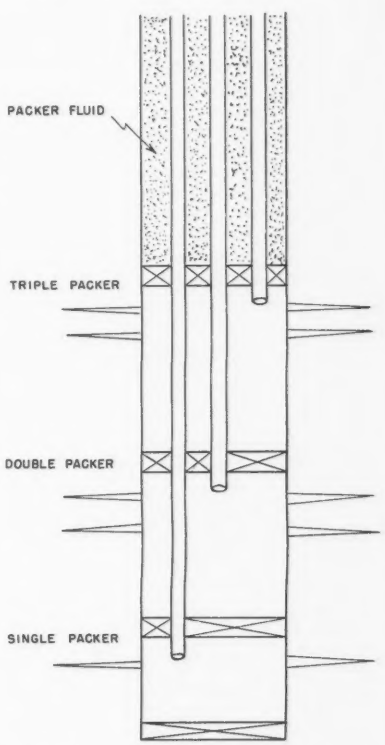


Figure 1—Schematic diagram of triple completion well. Packers and packer fluid are shown as the well is ready for production.

C. M. HUDGINS is a research chemist in the Materials Section of the Production Research Division, Continental Oil Co., Ponca City, Okla. He is concerned with corrosion and special physical chemistry problems encountered in production of oil. He has a BS and MS from Texas A & M College and a PhD from Louisiana State University.

JAMES E. LANDERS is associated with Continental Oil Company's Development and Research Department, Ponca City, Okla. An NACE member since 1952, he attended Southern Methodist University.

W. D. GREATHOUSE is supervisor of the Materials Section, Production Research Division, Continental Oil Co., Ponca City, Okla. He is co-author of several papers on petroleum production corrosion problems, has a BS in chemical engineering from Texas Technological College and is a member of NACE and AIME.

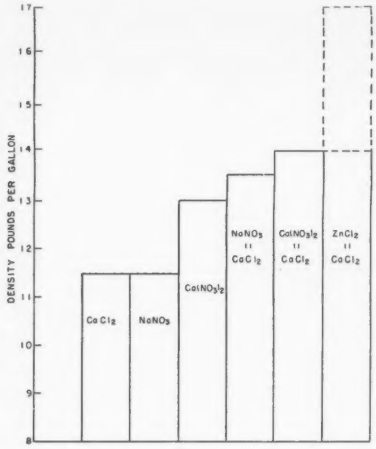


Figure 2—Densities attainable with various salt solutions used as packer fluids.

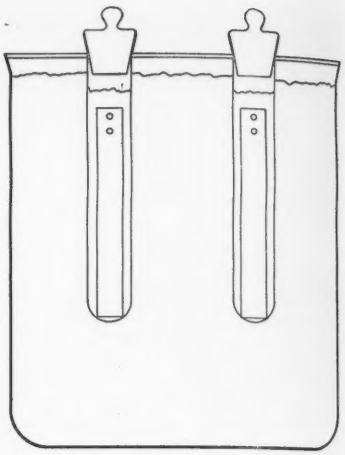


Figure 3—Immersion of test solution in hot oil bath.

TABLE 2—Composition of Solutions for $ZnCl_2$-$CaCl_2$ Corrosion Tests

Density, ppg	Percent by Weight			pH
	$ZnCl_2$	$CaCl_2$	H_2O	
12.8	22	31	47	4.8
13.5	30	27	43	3.9
14.3	39	23	38	2.0
14.7	44	21	35	1.6
15.5	51	18	31	0.7
16.2	61	13	26	0.2
17.0	72	0	28	—0.3

Sodium Nitrate

No extensive study of the corrosion of sodium nitrate solutions was undertaken, because stress corrosion cracking was observed. All weight losses observed corresponded to less than 1 mpy even with the addition of CO_2. Chromate, nitrate, and several inhibitors gave some protection, but the rates were again too low for reliable comparison.

Calcium Nitrate

Again, stress corrosion cracking was observed, and no extensive study of normal corrosion was made. It was noted that some forms of the material available commercially contained NH_4NO_3. There are numerous references in the literature to cracking and corrosion in NH_4NO_3 solutions.[4]

Calcium Chloride-Sodium Nitrate and Calcium Chloride-Calcium Nitrate Mixtures

Both of these systems will be discussed at the same time because of the similarity of attack and composition of the solutions. Sodium chloride precipitates from concentrated mixtures of $CaCl_2$ and $NaNO_3$. The resultant solution composition corresponds to $CaCl_2$-$Ca(NO_3)_2$ or $Ca(NO_3)_2$-$NaNO_3$ mixtures with small amounts of NaCl dissolved. Most of the tests were run in a solution made from technical $CaCl_2$ and $NaNO_3$ which had a composition of 36 percent $CaCl_2$, 11 percent $Ca(NO_3)_2$, and 53 percent H_2O. Less than 1 percent NaCl remained in solution.

Severe pitting was observed over a wide range of solution compositions, temperatures, pH, and steel types.[5] This pitting was observed in technical and chemically pure mixtures of both $CaCl_2$-$NaNO_3$ and $CaCl_2$-$Ca(NO_3)_2$. It occurred both in the presence of air and in systems where oxygen was excluded by continuous helium flow.

The ratio of NO_3^-/Cl^- affects the corrosion rate. A definite maximum pitting rate occurs with a few percent nitrate in $CaCl_2$. However, as the nitrate is consumed, the pitting diminishes. The most severe long-term damage then occurs at higher nitrate concentrations. Cracking becomes a problem in nitrates "contaminated" with chlorides at still higher ratios. The pitting rate was approximately 250 mpy at 210 F for the solution described above. It was essentially linear for 90 days (penetration of coupon from one side).

Temperature also has a very pronounced effect on the corrosion process. Relatively little corrosion occurs below 150 F, but is severe at 175 F. Further efforts to narrow the range indicate that corrosion "commences" between 160 and 170 F. It must be pointed out that the differences are not discontinuous and will certainly be a function of pH and probably solution and steel composition. Figure 4A shows the acceleration of corrosion at higher temperatures.

The pH of the solution also has an important role in the process. Little corrosion occurred in solutions saturated with lime (pH 9 or so), but the addition of a small amount of CO_2 or HCl to acidify to pH 6-7 will initiate the attack. The corrosion reaction apparently does not involve a pH rise and, once initiated, will proceed until the NO_3^- is used up. Continual addition of CO_2 or acid to maintain a pH less than 6-7 results in extremely severe attack, occurring even at temperatures below the 150 F discussed above. Figure 4B shows the effect of temperature on CO_2 saturated solutions. The 75 F test has obviously corroded by a completely different mechanism than the two other tests.

Eight different steels of interest in oil field operations were studied. The results are shown in Figure 5. There were variations in the number and depths of the pits from sample to sample. The important point is that only the 9 Cr sample escaped the pitting altogether. All of the others were subjected to the severe pitting attack and would not stand up for an "economical" life.

Approximately 50 different organic and inorganic materials were screened to see if they would eliminate the severe pitting. None had any lasting practical effect unless they reacted with nitrate and were used in quantities capable of removing all of the nitrate from solution. Two organic inhibitors showed good protection for about three weeks, but the protection broke down after that and the severe corrosion then occurred. Bases (e.g., lime, caustic) could stop the corrosion, but precipita-

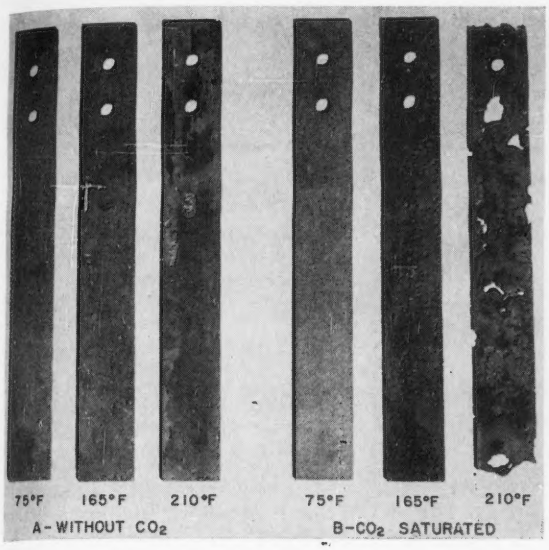


Figure 4—Effect of temperature and carbon dioxide (pH) on the corrosion process. A—Without CO_2, B—CO_2 saturated

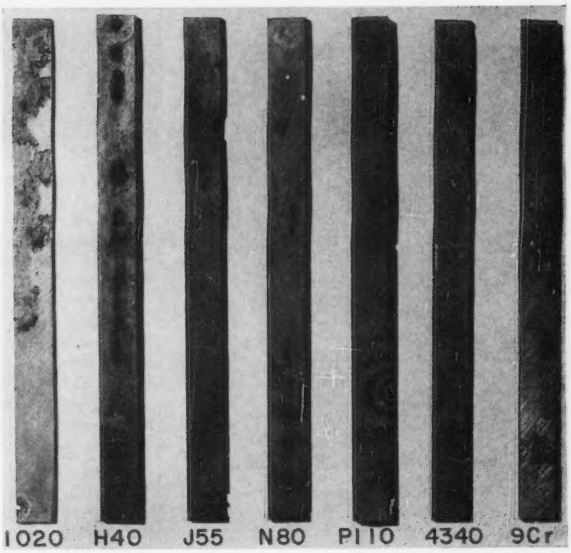


Figure 5—Attack of various steels by $CaCl_2$-$NaNO_3$ solutions at 210 F.

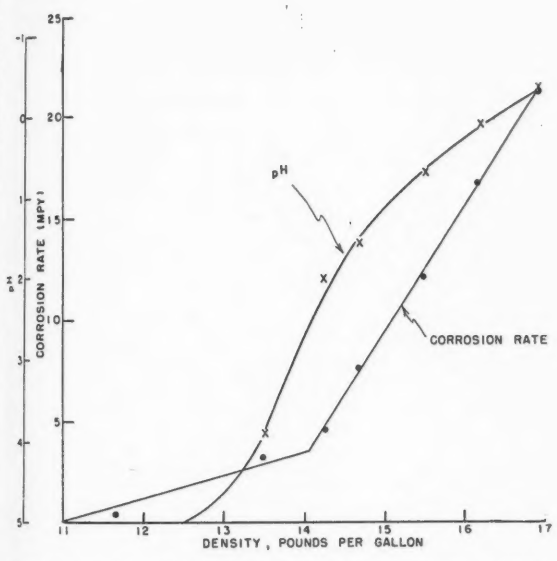


Figure 6—Corrosion rate and pH of $ZnCl_2$-$CaCl_2$ solution as a function of density. Composition is given in Table 2.

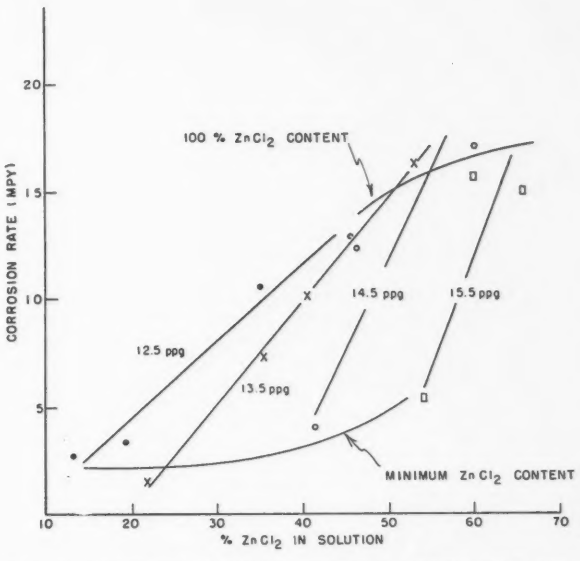


Figure 7—Corrosion rates of $ZnCl_2$-$CaCl_2$ solutions as a function of the $ZnCl_2$ content in solution.

tion of $Ca(OH)_2$ prevents any "reserve" basicity to combat possible CO_2 entry.

The mechanism of this attack is beyond the scope of this paper. However, two of the products are unusual and may serve to locate the corrosion problem in the field. Nitrous oxide (N_2O) is the principal gaseous product. It has been observed in a number of tests in the laboratory and has been identified in annular gas samples from the field. The solid corrosion product is magnetite, Fe_3O_4. It forms as an extremely hard and tightly adherent deposit in the corrosion pits. Chipping was frequently needed to remove enough of the scale to reveal the severe pitting.

Calcium Chloride-Zinc Chloride Mixtures

This system was developed to obtain densities greater than the 11.5 ppg available from $CaCl_2$ alone. Essentially, $ZnCl_2$ is added to the 11.5 $CaCl_2$ solution to get added density. However, both the cost and the corrosivity of the solution go up with increasing $ZnCl_2$ content. Careful determinations of the composition-solubility-density relationships and the corrosive characteristics of the system were necessary before the system could be used.[6]

Table 2 gives the composition of the solutions whose corrosivities are shown in Figure 6. These compositions were chosen close to the solubility curve (75 F) for the system so that $ZnCl_2$/$CaCl_2$ ratio would be at a minimum for a particular density. Note that the pronounced increase in corrosion rate occurs essentially at the same density as the rapid decrease in the pH of the solution. The decreasing pH is due to the hydrolysis of $ZnCl_2$ into basic zinc chloride complexes and HCl. The pH values noted on the graph represent reasonable agreement between glass electrode and narrow-range pH paper. However, because of the high concentration of salts, they may not have absolute meaning. The effect of excess amounts of $ZnCl_2$ on the corrosion rates of various weight solu-

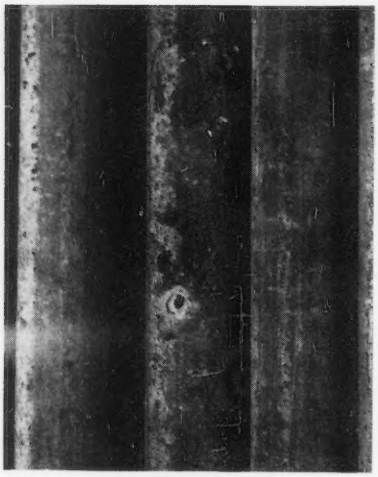


Figure 8—Severe pitting on tubing exposed to $CaCl_2$-$NaNO_3$ packer, Well A.

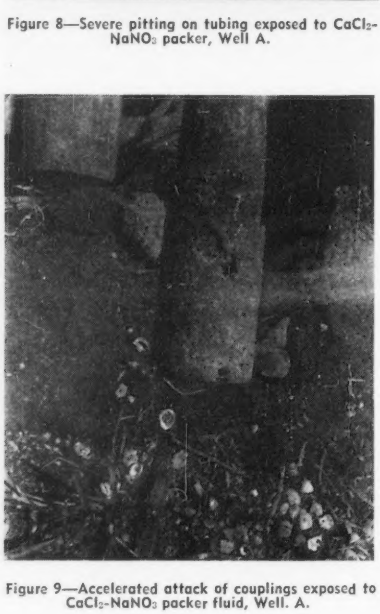


Figure 9—Accelerated attack of couplings exposed to $CaCl_2$-$NaNO_3$ packer fluid, Well. A.

tions is shown in Figure 7. These data show that high corrosion rates can be obtained even at lower densities if excessive amounts of $ZnCl_2$ are used.

The attack on all these coupons was very uniform. Some of the longer-term, high corrosion rate tests did show some etching characteristics of the coupons, but no pitting or other localized attack was observed.

A number of inhibitors were screened for effectiveness and solubility. The solubility factor eliminated most of the "water soluble" inhibitors without further testing. Several of the inhibitors that were soluble gave greater than 90 percent protection in 30-day tests.

From these results, it was concluded that $CaCl_2$-$ZnCl_2$ solutions could be used up to 14 ppg, provided a minimum amount of $ZnCl_2$ was used. This conclusion was based on the premise that the uninhibited solution must be safe. In the absence of long-term data for inhibitors under well temperatures and pressures, the inhibitors are added only as low cost insurance.

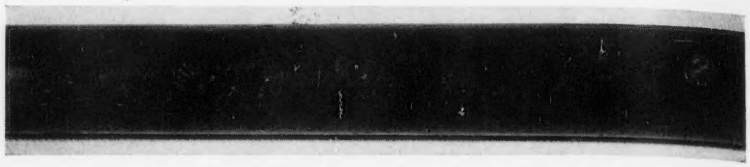


Figure 10—Numerous penetrations in tubing from Well A, opposite top producing zone.

Field Experience

To date all of the experimental field data have confirmed the laboratory corrosion tests. No appreciable corrosion had occurred on the tubing pulled from a $CaCl_2$ packer solution after one year. No tubing has yet been pulled from a well with a $CaCl_2$-$ZnCl_2$ packer fluid.

Tubing has been examined from two wells with calcium chloride-sodium nitrate mixtures in the annulus. Well 'A' was initially completed with $NaNO_3$ solution. After several cracked couplings were discovered, the nitrate was "displaced" with $CaCl_2$ solution. Considerable mixing (or dissolution of excess solid sodium nitrate) occurred. After 18 months the tubing again had to be pulled from the well. Severe pitting with numerous penetrations had occurred on the external surface of the tubing strings from about 7100 feet (estimated 160 F) to the triple packer at 9534 feet (180 F). Figures 8 and 9 show examples of this attack. Even more severe attack occurred opposite the top zone. One six-foot sample from this area (Figure 10) had eight penetrations. No corrosion occurred in the lower two zones. Magnetite (Fe_3O_4) was found over the corroded areas.

Well 'B' was a triple completion with an early style triple packer at 6123 feet (approximately 150 F). No appreciable corrosion had occurred on the tubing exposed to the brine above this packer. Severe pitting was observed for about 120-150 feet below the triple packer on both the dual and single strings. No corrosion was evident on down to the perforations at 6320 feet. Little or no corrosion was observed below the perforations in the top zone or in either the dual or single zones. The top zone produced oil with small amounts of water and gas. A $CaCO_3$ deposit was found on the inside of the tubing, producing from the top zone. Magnetite and siderite ($FeCO_3$) were present on the tubing in the pitted area. It was concluded that packer solution seeping past the packer was acidified by formation fluids (CO_2). Corrosion developed on the tubing down to the area where turbulent flow from the perforations washed the packer fluid from the tubing.

Complete penetration of the tubing (and presumably the casing) had occurred in both of these wells within 18 months. This is roughly the rate that would be expected from the laboratory studies. This, plus the similarities in attack, gaseous products (N_2O) and corrosion products (Fe_3O_4), is ample evidence that:

1. The field and laboratory corrosion phenomena observed are comparable.
2. The corrosion attack is severe.

Summary

Laboratory and field experience has shown that nitrates and nitrate-chloride mixtures are not suitable for packer fluids. Stress corrosion cracking was observed in both sodium and calcium nitrate solutions and in mixtures of these with $CaCl_2$. Mixtures of these nitrates and chlorides were also found to be extremely corrosive with severe pitting at the rate of ¼ inch per year. No appreciable corrosion has been found in straight NaCl or $CaCl_2$ solutions. $CaCl_2$-$ZnCl_2$ mixtures have acceptably low corrosion rates up to 14 pounds per gallon, provided a minimum amount of $ZnCl_2$ is used to obtain a given density. Higher densities and/or zinc chloride concentrations result in excessive corrosion.

Acknowledgments

The authors acknowledge the capable efforts and useful suggestions of H. B. Berry, who performed most of the experimental work reported herein. They also wish to thank Continental Oil Company for permission to publish this work which was performed in their laboratories.

References

1. *Petroleum Week*. 8, No. 13, 22 (1959) Mar. 27
2. R. L. McGlasson, W. D. Greathouse and C. M. Hudgins. Stress Corrosion Cracking of Carbon Steels in Concentrated Sodium Nitrate Solutions. *Corrosion*, **16**, 557t (1960) Nov.
3. H. H. Uhlig. Corrosion Handbook. John Wiley & Sons, Inc., New York, 1948, p. 131
4. Uhlig. *Ibid*, p. 132
5. J. W. Mellor. A Treatise on Inorganic Chemistry. Volume VIII, Longmans, Green and Co., New York, 1940, p. 453
6. A. Seidell and W. F. Lipke. Solubilities of Inorganic and Organic Compounds. Supplement to the Third Edition D. Van Nostrand Co., New York, 1952, p. 118

DISCUSSION

Question by Glenn Ray Roberson, Standard Oil Co. of Texas, Houston, Texas:

What type of inhibition is used in the brines?

Reply by C. M. Hudgins:

Ethylene oxidized organics.

Question by Kelly H. Roach, Lafayette, Louisiana:

Have you any information with regard to excessive temperatures (300 F) on dense salt solutions either inhibited or uninhibited?

Reply by C. M. Hudgins:

We are just starting this work and do not have any data at this time.

Stress-Corrosion Cracking Of High Strength Oil Country Tubular Goods*

By R. S. LADLEY

Abstract

Major advances in fabrication and handling of oil country tubular goods have improved mechanical performance, but catastrophic failures caused by stress-corrosion cracking have been steadily increasing. Failure experience with N-80, 9 percent Ni, 9 percent Cr, and AISI 4340 tubing and N-80 casing is enumerated and the failure significance discussed. The status of the problem is discussed with respect to the corrosion mitigative measures currently available. Consideration also is given to what is needed in the future to properly apply high-strength tubular products in oil and gas well environments. 3.5.8

Introduction

THREE OIL country engineers recently led a panel discussion concerning the drilling of a 50,000 ft. well. All recognized the need for improvements in materials and advancements in technology before a 50,000 ft. hole could ever be bottomed. Major improvements have been made in tubular products during the past decade. Yet, material performance has been, is, and will probably continue to be critical as the higher pressures and temperatures of deeper pay zones are encountered

Tubular goods failures plagued the industry when high pressure wells were first produced. This high failure incidence caused initiation of a three-pronged program—inspection, handling, and material improvements.

Inspection of tubular goods has progressed to the point where a specification could be written to include most of the producing companies' requirements.

Handling technology has advanced to a point where tubing back-up tongs leave no more than 5 mil deep marks, tubing tongs leave less than 10 mil marks,[1] and drill pipe can be handled without marking the body of the pipe at all. Manufacturers of tubular products have taken major steps to eliminate tong marks incurred when couplings are put on at the mills and to eliminate other like defects.

Tubular materials have been improved to provide reasonable ductility at high strength levels, and quality control methods have been utilized to hold strengths down to a usable level. Research is continuing, both for more ductile alloys and for methods to evaluate the mechanical suitability of alloys for critical oil-field service.

Mechanical failure frequency decreased with these improvements, and failures caused by corrosion became more obvious. Penetration due to metal loss by pitting has long been a problem, but is one which can be controlled to a great extent.

Failures caused by cracking pose an entirely different problem; all indications are that it is becoming more severe with time. Sulfide-stress cracking is currently being controlled by using alloys with controlled strength ranges.[2] Stress-corrosion cracking, which is not associated with large amounts of hydrogen sulfide, is not so easily controlled. In the author's company, stress-corrosion cracking is now the major cause of tubing failure. It is still too early to know the extent of the cracking problem in casing.

★Submitted for publication February 23, 1960. A paper presented at the 16th Annual Conference, National Association of Corrosion Engineers, Dallas, Texas, March 14-18, 1960.

About the Author

R. S. LADLEY has been engaged in metallurgical and corrosion work with Phillips Petroleum Company since 1954. He is currently Supervisor, Tubular Products Section, of Phillips' Test Division Laboratory. He was graduated from the University of Illinois in 1952 with a BS in Metallurgical Engineering. He is a member of NACE, Bartlesville, Oklahoma, Engineers Club, American Society for Metals, and is Chairman, Task Group on Equipment, NACE Unit Committee T-1E.

Stress-Corrosion Cracking Failures

Stress-corrosion cracking has not been selective in affecting just one alloy. Failures have been experienced in N-80 tubing and casing, 9 percent nickel tubing, 9 percent chrome tubing, AISI 4340 tubing, and possibly in P-110 casing.

N-80 Tubing and Casing

Two failures in N-80 tubing in condensate well service were unique in that each initiated on the outside surface of the tubing (Figure 1). The tubing was in service for three years in a 15,000 ft. well completed with a packer. There was a light weight mud in the annulus. There had been some joint leakage, but it could not be determined if the major gas leakage was through the joints or from stress-corrosion cracks which penetrated the wall (Figure 2). Both of these failures were caused by residual stresses. Roll straightener marks were still visible on the outside surface, and the cracks were following the plastically deformed area left by the rolls (Figure 3). The agent causing the cracking was not identified, but the tubing was exposed to mud, CO_2, organic acids, and trace amounts of hydrogen sulfide.

An N-80 tubing string in another well in the same field was pulled after seven years of service because of excessive pressure on the casing. Metal loss due to corrosion was nil, but there were three different instances of stress-corrosion cracking. The tailpipe had cracked due to the high make-up stress in the flush joints. A coupling near the middle of the string had failed because of high hoop stress from make-up. A length of casing near the top

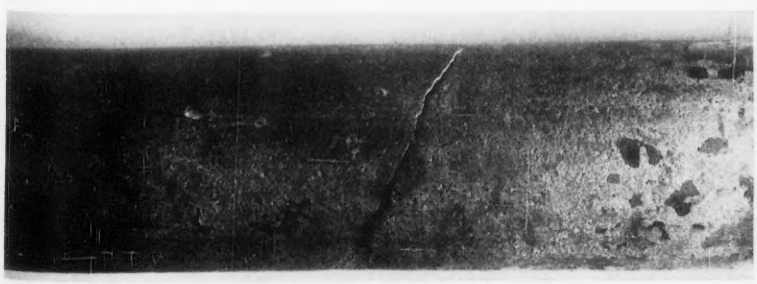


Figure 1—Spiral split in N-80 tubing.

Figure 2—Fracture surface of parted N-80 tubing. Shear failure is shown on the right; gradual to complete penetration of wall by stress corrosion cracking is shown on the left.

Figure 3—Magnetic particle indications of cracks following roll straightener marks in N-80 tubing.

of the hole failed circumferentially due to high tensile stress. The tailpipe and coupling failures both initiated on the outside surface, the casing failure on the inside surface (Figure 4). The exposure conditions were essentially the same as for the first two failures discussed, excepting that the tailpipe was exposed only to well fluids. Again, the cracking agent could not be identified.

The cracking found in all these N-80 failures was highly branched—typical of stress-corrosion cracking (Figure 5). The microstructure was normal for a normalized N-80 material. The mechanical properties were well within the N-80 range, as none of the failed tubes had a hardness over Rockwell C 24.

9 Percent Nickel Tubing

Stress-corrosion cracking failures in 9 percent nickel tubing have been reported frequently over the past several years. In the author's experience, seven body failures have occurred in sweet condensate well service after four to five years. These failures were in the form of small cracks on the inside surface, and were found initially by hydrostatically testing to pressures over 5000 psig. Once the leaks were pinpointed, the cracking could be defined by magnetic particle methods (Figure 6).

In another condensate well, a 1000 ft. tailpipe string (i.e., that part of the tubing string which extends below the packer) virtually disintegrated because of stress-corrosion cracking after about five years of service. The perplexing thing, as with the body failures, is that the agent causing the cracking was never determined. All 9 percent nickel failures were associated with mechanical properties—a stress-corrosion cracking failure has not occurred in tubing with a hardness below Rockwell C 22 (a hardness of C 22 corresponds roughly to a yield strength of 105,000 psi).

One body failure of a different type occurred in 9 percent nickel tubing. This was a split, at a very low differential pressure, in a severe, 0.030" deep backup tong mark (Figure 7). Failure was due to stress-corrosion cracking which initiated on the outside surface in the tong mark. There had been no communication to the annulus in this packed-off condensate well, so the cracking agent must have been in the packer mud. No positive identification of the agent could be made.

AISI 4340 Tubing

Identification of a contributing agent was made in a series of 4340 failures. Arsenous oxide was found in the cracks. This 4340 tubing had parted when pulling a sweet condensate well to recomplete it with larger tubing. Parting was due to stress-corrosion cracking, circumferentially oriented from high tensile stress (Figure 8). The cracks initiated on the inside surface. The arsenous oxide suggested some form of hydrogen embrittlement since arsenic promotes absorption of hydrogen. One investigation showed sulfides to be present, but this could not be fully substantiated in the over-all examination, although a trace of hydrogen sulfide (less than 3 ppm) was present in the produced gas.

The rest of the 4340 tubing string was hydrostatically tested after recovery from the well. Twenty-three splits occurred at pressures below 5000 psig in the first 87 lengths tested. Examination showed stress-corrosion cracking had occurred in all the failed lengths, and that the cracks were both circumferentially and longitudinally oriented. A closed yield range of 105,000 to 125,000 psi had been specified for the tubing, and the hardness ranged from Rockwell C 25-33.

Other stress-corrosion cracking failures have occurred which initiated on the outside surface of 4340 tubing. As far as is known, the outside of the tubing was exposed only to the packer mud. Three longitudinal failures examined were associated with tong marks (Figure 9). These failures almost certainly were caused by residual stresses from cold working by the tongs, because the differential pressure at their location just above the packer was nearly zero. More failures of this type have been found but have not yet been examined.

Box ends of integral-jointed 4340 tubing have also been affected from the outside surface. A box containing cracks

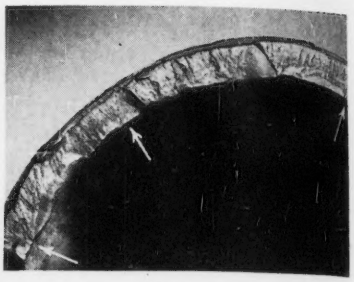


Figure 4—Fracture surface of parted N-80 casing. Arrows point out multiple points of fracture initiation.

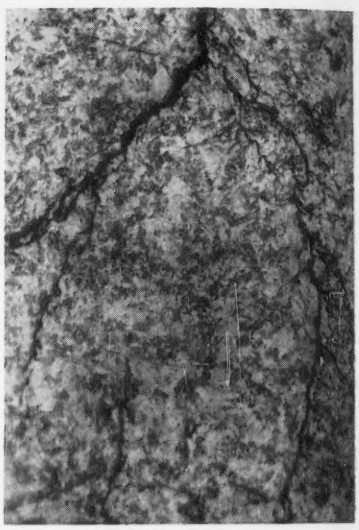


Figure 5—Typical stress corrosion cracks in N-80 material. Vilella's etch, approximately 170X.

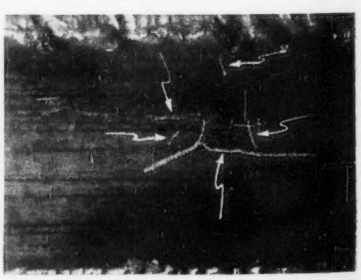


Figure 6—Magnetic particle indications of cracks in 9 percent Ni tubing.

is shown in Figure 10. These numerous, small cracks have initiated brittle splits, and, like the cracks in the other 4340 failures described, are typical of stress-corrosion cracking (Figure 11).

9 Percent Chromium Tubing

An "unexplainable" failure was experienced in 9 percent chrome-½ percent moly tubing several years ago. The tubing, on the lower end of a specified hardness range at Rockwell C 20, cracked and split longitudinally just below the upset. Only one length in 450 cracked. The pressure was moderate, below 5000 psig. The tubing was exposed

Figure 7—Magnetic particle indication of stress corrosion cracking in a tong mark in 9 percent Ni tubing.

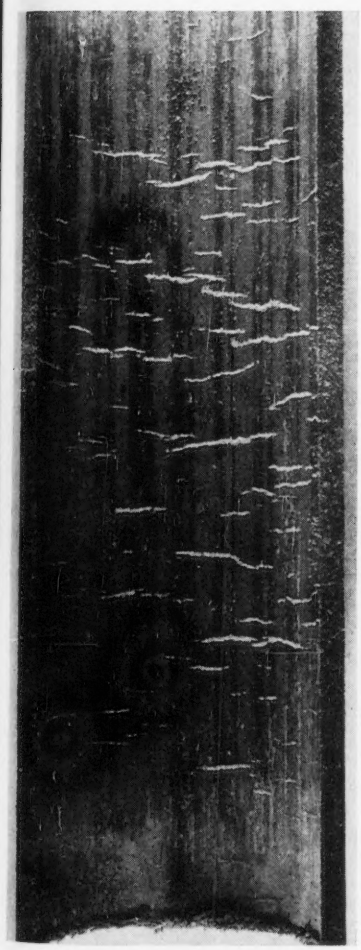


Figure 8—Magnetic particle indications of cracking in 4340 tubing.

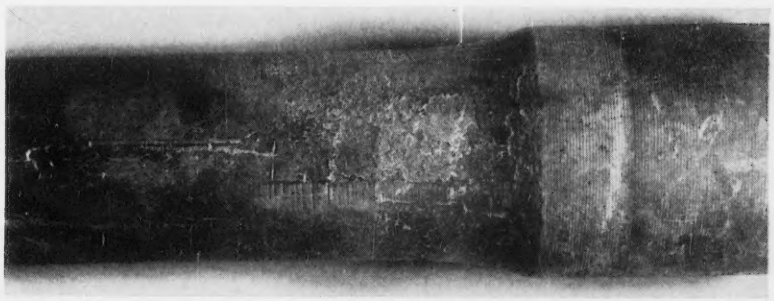


Figure 9—Magnetic particle indication of cracking next to a tong mark with washout in 4340 tubing.

to carbon dioxide with trace amounts of hydrogen sulfide in sweet condensate service. This same string of tubing was re-run and has given trouble-free service for more than three years. Other 9 percent chrome strings in this field have been in service for over 3½ years with no failures.

A 9 percent chrome string run recently in this field, however, parted in three separate lengths after just six months of service (Figures 12 and 13). Cracking initiated on the inside surface, and was typical of stress-corrosion cracking (Figure 14). Eight other lengths were found which contained cracks. No metallurgical abnormalities could be found, although the cracking was confined to an area 7″-22″ below the upset in all eleven lengths. The hardness, Rockwell C 19-26, was below average, cracking was not associated with mechanical damage, and the cracks occurred on either one end of a length or the other—never on both. This mystery is yet to be solved.

Discussion

One worthwhile observation has come from these failure studies—there have been no stress-corrosion cracking failures reported in J-55 tubing. It has been well established that there is a relationship between sulfide-stress cracking and strength. Practical application of this concept has resulted in a high degree of reliability of tubular goods in sour condensate service. In the author's experience with sweet wells, there have been no stress-corrosion cracking failures of 9 percent nickel tubing when the hardness was below Rockwell C 22. Further evidence of a strength-cracking relationship has come from investigators who have shown that ultra high-strength steels are susceptible to stress-corrosion cracking in atmospheric environments.[3] Unfortunately, any relationship that might exist with 9 percent chrome, 4340, and other alloys in familiar strength ranges is not clear.

Utilization of lower strength steels could ease the problem temporarily, but low strength steels have a practical limit for use in very deep, extra high-pressure wells. Coatings might help to minimize the cracking problem, but a small holiday or mechanically damaged area might well be enough to result in failure. Inhibitors have been used successfully to stop stress-corrosion cracking, have made

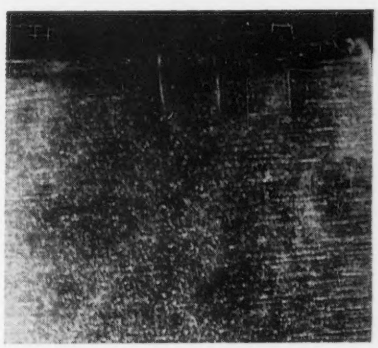


Figure 10—Cracking in the box end of integral joint 4340 tubing. Black light photo of magnetic particle indications.

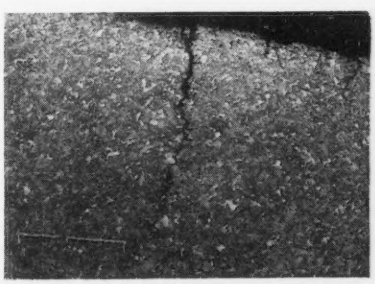


Figure 11—Intergranular cracking with slight branching in 4340 tubing. Nital etch, approximately 50X.

work with tools run on wire rope possible in sour wells, and have been used to stop hydrogen blistering. Inhibitors are not yet a foolproof solution, because there have been instances in each of the three cases where the problem was not solved by inhibitors. Alloy steels and non-ferrous alloys are available, but their behavior is not fully understood. The majority of the high alloy, corrosion resistant materials have not been tried in oil well environments as tubing or casing.

If the causes of cracking failures were understood, the proper mitigation method could be determined much more readily. One fact was common to all the failures described—the actual agent causing the failures was not known. It is not known for example if carbon dioxide causes the cracking; it is not known whether or not trace amounts of hydrogen sulfide are sufficient and the

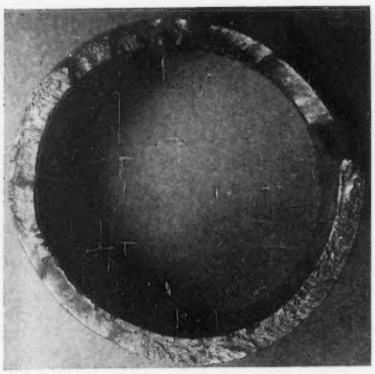


Figure 12—Fracture surface of parted 9 Cr tubing. Partial and complete penetration by cracking is shown in the top and left portions of photo.

problem really one of sulfide-stress cracking. Nor is it known if the problem is one of hydrogen embrittlement that is aggravated by poisoners like arsenic. It is not known if either organic acids or bacteria are involved.

Along with determination of causative agents, the degree of susceptibility of various alloys is also important. It is possible that one alloy will work in one place where another will not, and vice versa. It would be helpful to know just how much effect increased strength in a given alloy has on its cracking susceptibility. In other words, to determine what conditions are necessary to cause failure. It should be determined also if metallurgical phenomena are the primary factors, if applied and residual stresses are most important, or if a combination of circumstances are involved.

Summary

All alloys are susceptible to stress-corrosion cracking under the proper conditions. The partial list of questions regarding causative agents, degree of susceptibility, and necessary conditions to cause failure need answering more and more as cracking failures become more predominant. The best way to avoid the expense of learning through costly, sometimes disastrous, failures is to know the cause. Phillips is continuing field and applied research in attempting to identify the agents and pertinent conditions, and to evaluate alloy susceptibility. Other companies are conducting similar

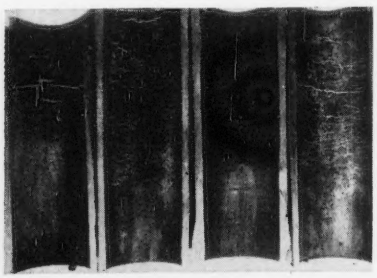


Figure 13—Magnetic particle indications of cracking which caused failure shown in Figure 12.

investigations, and current data indicate that partial answers already may be available.[4,5] But, it will take the bulk of the industry and tubular goods manufacturers working together to find an effective solution. When the solution to downhole stress-corrosion cracking failures is found, one giant step will have been taken toward successful completion of the first 50,000 ft. well.

Acknowledgment

The author wishes to express his appreciation to the management of Phillips Petroleum Company for permission to publish this paper.

References

1. John Province and Duane Marquis. Tubing Handling Tools and Procedure. *Petroleum Engineer*, 31, No. 11, B-23 (1959) October.
2. Symposium on Sulfide Stress Cracking. *Corrosion*, 10, No. 8, 325 (1952) October.
3. F. K. Bloom. Stress-Corrosion Cracking of Hardenable Stainless Steels. *Corrosion*, 11, No. 8, 351t-361t (1955) August.
4. R. L. McGlasson and W. D. Greathouse. Stress-Corrosion Cracking of Oil Country Tubular Goods. *Corrosion*, 15, No. 8, 437t-442t (1959) August.
5. J. P. Fraser and G. G. Eldredge. Influence of Metallurgical Variables on Resistance of Steels to Sulfide Corrosion Cracking. *Corrosion*, 14, No. 11, 524t-530t (1958) November.

DISCUSSION

Question by R. F. Weeter, Midland, Texas:

You mentioned failure of 9 Cr, 1 Mo in trace hydrogen sulfide environment. What do you consider a trace?

Reply by R. S. Ladley:

In this case less than 3 ppm.

Question by John H. Naschke, Houston, Texas:

Have you correlated failures to acidizing inhibitors such as arsenic?

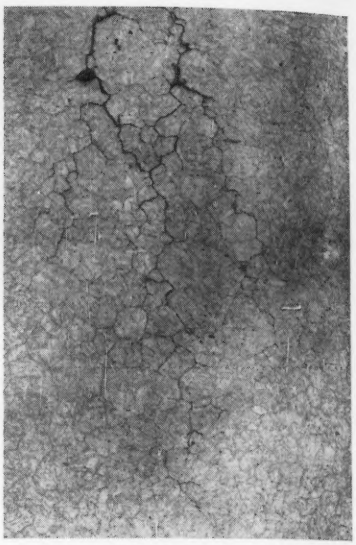


Figure 14—Intergranular, highly branched cracks in 9 percent Cr tubing. Vilella's etch, approximately 50X.

Reply by R. S. Ladley:

No. In two failures arsenic was found to be present in the cracked area, and in one of these, arsenic was found in the cracks. The only source of arsenic we know about is from the acidizing inhibitor which was used.

Question by E. H. Muehlhaase, Dallas, Texas:

Were you producing liquid water in any of the wells experiencing stress corrosion cracking?

Reply by R. S. Ladley:

Yes. Normal condensed water production of 1 barrel per million cubic feet was produced in all the condensate wells.

Question by L. W. Vollmer, Pittsburgh, Pa.:

Hardness is not a good parameter of the other properties of 9 percent Cr-1 percent Mo Steel. For the 9 percent Cr tubing failure with Rc20 hardness, were other properties high or low?

Reply by R. S. Ladley:

Our work with 9 Cr-½ Mo tubing has shown that a hardness of Rockwell C 20 would have a low yield strength, in the vicinity of 90,000 psi. C-ring tests indicate excellent notched-ductility at this hardness level.

Any discussion of this article not published above will appear in June, 1961 issue.

New Developments in the Mitigation of Corrosion In the Utility Field*

By E. H. THALMANN

Abstract

The use of distributed high silicon cast iron anodes for corrosion protection of an underground lead-covered cable distribution system is discussed. Electrolytic zinc cells for use on pipe-type cables and for control of induced voltages on pipelines also are considered.

The use of well-type ground beds for cathodic protection of buried metallic structures at generating stations is described, and methods of protection of silicon rectifiers from damage because of surges are explained. The use of concrete as a coating on steel structures in shielded areas of cathodically protected complex systems is described. Other topics discussed include condenser water-box corrosion and dangers from stray current discharges.

The use of zinc rich paint for protection of steel in certain situations is covered. Comparisons are made with conventional primers. 5.2.1

Introduction

CORROSION OF the sheaths of lead-covered cables of an underground electric distribution system is influenced by electrolytic cells which are dependent upon many factors. Of prime importance to the cable life are such elements as (1) materials of construction of the duct system, (2) condition of the duct walls, (3) nature of and contamination of duct and manhole mud and water, (4) type of lead from which the sheaths are constructed, (5) nature of the outer jacketing material, if any, (6) type of system grounding conductor and its proximity to the cable sheaths, and (7) presence of stray direct currents which might cause sheath electrolysis.

Cable Corrosion Problem

An underground electric distribution system on the Gulf Coast was studied in which bare lead-sheathed cables installed in concrete-encased 4-inch fiber ducts continued to corrode although a cathodic protection system had been installed to arrest corrosion. The manholes generally were of reinforced-concrete construction, with a bare copper manhole grounding cable encircling the manholes at floor elevation. The bare copper grounding conductor was carried in the duct system in a separate inside duct. The normal water table was above the duct lines, and in some cases there was salt water infiltration into the conduit system. The average manhole water resistivity was found to be in the order of 400 ohm-cm at a pH of 7.8. Potable water had a resistivity of approximately 520 ohm-cm and a pH of 7.5. Some manholes contained water whose level rose and fell with the tide.

During a routine inspection and cleaning of the manholes in 1954, it was observed that there was considerable corrosion of the cable sheaths. Investigation indicated that a reddish-brown corrosion product covered the tops of the cable sheaths where there was no fireproofing on the cables, but where mud had been deposited on the sheaths when the water level in the manholes receded below the level of the cables. Large quantities of oyster shell dust provided alkalinity to the mud deposited on the sheaths, which attacked the lead. Cursory examination indicated that the lead was in good condition where it was shielded from mud by fireproofing, but later detailed observations showed attack under the fireproofing. This was a result of free alkalinity in the fireproofing material. The low resistivity of the soil also had caused corrosion on other underground facilities. This led to placing the major part of the gas system under cathodic protection.

About the Author

E. H. THALMANN, Principal Electrical Engineer for Ebasco Services Inc., New York City, holds the degree of BEE from the Cooper Union Institute of Technology. He joined Ebasco in 1941, and is responsible for corrosion control projects, both domestic and foreign, for electric power plants, underground cable systems, underground structures at industrial plants, transmission and distribution piping systems, and for general corrosion studies and investigations. He is currently chairman of NACE Technical Committee T3-D on Instruments for Measuring Corrosion.

Operating personnel installed impressed-current anodes in carbonaceous backfill adjacent to the duct lines to provide cathodic protection to the buried cable sheaths. No attempt was made to insulate other interconnected buried metallic structures from the cable plant. The anodes were energized from an overhead 125/250 volt d-c system where it was convenient to the underground plant. A rectifier was installed beyond the area of the d-c system to energize a system of anodes installed adjacent to manholes on that portion of the conduit system.

A study made after several years operation, during which time cable failures continued, indicated that the protective effects from the impressed-current anodes were localized to the duct lines adjacent to the anodes. Where anodes were adjacent to manholes, alkaline deposits were formed on cable sheaths from high current densities, in addition to the free alkali found in some of the fireproofing material. Corrosion of the sheaths from alkali attack at these locations was feared if the cathodic protection installation should become de-energized. Also, it was observed that a potential danger existed from formation of lead hydride, and attendant hazard to the lead sheaths, because of highly-negative sheath potentials.

During a program to insulate the cable sheaths from the alkaline fireproofing in the manholes, opportunity was afforded to measure the depth of pitting of the cable sheaths. Several indications were observed of pitting depths 75 percent of the original sheath thickness. Remedial measures involved de-energizing a circuit, removing the fireproofing, cleaning the cable sheath, painting the sheath with rubber cement, applying polyvinyl chloride tape to the sheath, and refireproofing the cable. Thus, the sheaths of the various circuits were cleaned, inspected, repaired where necessary, and taped to remove the influence of alkaline products from the fireproofing. The use of uncured butyl rubber extrusions as a filler material adjoining splicing sleeve wipes is considered suitable for smoothing the abrupt transition from sheath to sleeve diameter under either polyvinyl chloride tape or laminated butyl and polyvinyl chloride tape.

The influence of the bare untinned copper grounded neutral conductor on the corrosion of the lead sheaths is indicated by the fact that a section one block long, which was isolated from the cable plant, had a resistance to the remainder of the cable plant of 8.5 ohms. Immediately upon opening the circuit, a short-circuit current to the cable plant of 42 ma was measured, with the copper neutral collecting current, and a galvanic cell driving voltage of 350 mv. If all this current were to flow from the cable sheaths, a loss of lead of approximately 3 pounds in one year could result. Inasmuch as the cable sheaths were interconnected with the other underground structures, all this current did not necessarily discharge from the lead. However, the importance of the galvanic cell formed between the closely coupled copper and lead in adjacent ducts is illustrated. It was recommended that the bare neutral conductor be removed and be replaced with neoprene-jacketed neu-

*Submitted for publication March 14, 1960. A paper presented at a meeting of the South Central Region, National Association of Corrosion Engineers, Denver, Colorado, October 12-15, 1959. This paper was also given at the NACE Canadian Region Meeting (Eastern Division), Toronto, Canada, January 18-21, 1960.

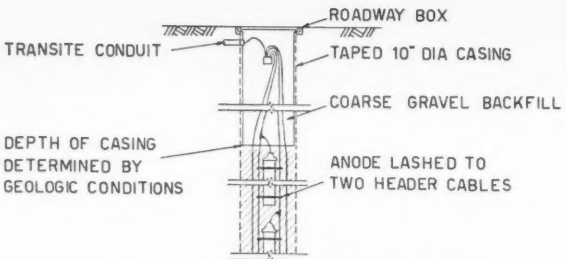


Figure 1—Open-hole type deepwell ground bed.

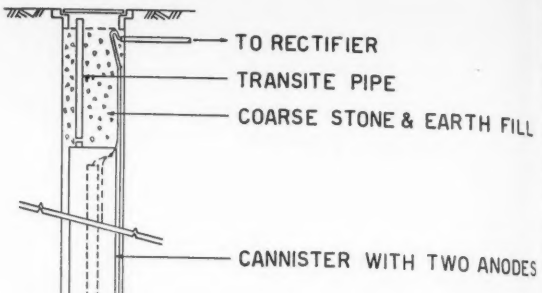


Figure 2—Cannister-type deepwell ground bed.

tral conductor, and that manhole grounding cables be replaced with insulated copper conductors.

Duct Slug Surveys

Duct slug surveys were conducted to ascertain the condition of the ducts. The test was performed by drawing a section of lead-covered cable, approximately 12-inches long, to which a long insulated test lead and pulling eyes had been fitted, through a vacant duct. During this survey an interval of four feet was used between measurements. Measurement was made at each interval of the galvanic potential and galvanic current between the cable and slug, and of the cable-to-slug resistance.

The resistance obtained between the cable plant and the duct slug is roughly equal to the resistance that would be measured between one foot of cable and the other cables in the conduit system, if the duct occupied by the duct slug were occupied by cable. The resistance is essentially equal to the resistance of the duct wall, and is therefore controlled by the condition of the duct. This resistance value proves helpful in analyzing the likelihood of corrosion in a particular duct run. Ducts in which slug resistances of 250 ohms, or less, are measured are considered unfavorable from the corrosion standpoint. It would be desirable to have resistances in excess of 1000 ohms. Anodic and cathodic areas can be determined from the cable-to-slug potentials.

Tests conducted during this study showed that very low duct-slug resistances prevailed throughout the conduit system and that effects of the cathodic protection system as installed were localized, with much of the current collecting on other interconnected utility structures. Although the existing installations helped to retard corrosion in local areas, rapid sheath corrosion could be expected to continue unless improved distribution of the cathodic protection current were made. Sheath potentials adjacent to impressed-current anodes of —2.2 volts to a lead reference were measured. This approaches the value at which lead hydride can be formed, with attendant dissolution of the sheath.

Proposed Protection System

It was recommended that the entire distribution system be placed under cathodic protection by means of high silicon-iron duct anodes. These anodes were to be spaced at 5-ft intervals, installed in vacant ducts, and energized from the d-c distribution system where it was available, and from feeders from an existing rectifier beyond the 125/250 volt d-c system.

Test at various anode spacings indicated that a maximum of about 5-ft spacing between anodes should be employed in order to provide good current distribution to the cable sheaths without causing interference to other sub-surface structures because of excessive current requirements.

The Type G Duriron anode was employed, with No. 4 Awg high-density, linear polyethylene insulated cable, chosen on the basis of its mechanical strength and the excellence of the insulating qualities of polyethylene. High-density polyethylene was chosen because of its resistance to environmental stress cracking. The polyethylene caps on the ends of the anodes were of material assistance to easy installation because they permitted the anodes to ride over obstructions in the ducts.

The anode strings were arranged in one-block lengths so that they could be isolated from one another in the event of trouble. Nominal current requirements of 500 ma per block were anticipated. Current control in the downtown area was with the use of 120-volt lamps of varying wattage ratings in series with the anode strings and the positive 120-volt d-c bus. Power resistors of adequate size and rating could not be installed for the same cost as lamps, nor would they have been so readily available. The use of lamps also provided quick means of determining whether the installation was functioning. Duct-slug surveys were used after installation to adjust current discharge from the various anode strings. The surveys after installation indicated that sheath corrosion can be controlled when the currents have been adjusted to the requirements of the various duct banks as determined by duct surveys.

Criteria for Protection

The potential of anodic or bright lead measured to a $CuSO_4$ reference electrode generally would be between —0.52 and —0.62 volt, with a wider range in some cases, depending upon the environment. In many environments a protective surface film forms on lead, rendering it passive to local environments, and with a less negative potential. The potential of a clean test slug to a $CuSO_4$ reference electrode trailed close behind would closely approximate the potential of anodic lead in various parts of a duct bank. The potential of the cables to the same electrode would be a weighted average of their potentials, modified by IR drops in the medium between electrode and cables. Cable-to-slug voltage is the difference between voltages to the electrode.

A bright test slug simulates an anodic area on a cable in the test duct. A positive cable-to-slug voltage generally indicates an anodic area in which current would discharge from a cable sheath. It may be noted that in a fully passive area small positive voltages would be registered to a bright slug. In such an area, the potential of the bright slug usually would be less than —0.62 volt to $CuSO_4$, and in general slug resistance would be fairly high; moreover, a slug left in the area would assume a less negative potential in time.

In general, cables would be protected where their potentials are made somewhat less negative than that of bright lead. However, some margin is necessary because of IR drops and differences in conditions of the cable ducts and the

test duct. Usually protection is achieved where cable-to-slug potentials are 150 mv, or more, negative or are changed 200 mv negative as compared with unprotected conditions. (A passive section would be safe with less voltage change; however, such sections generally change readily). The potential to a $CuSO_4$ electrode usually would be in the order of —0.72 to —0.82 volt, but irregularities in current distribution will often result in higher potentials (of —1.0 volt or more) in parts of a duct. Corrosion from alkali formed from salt water at potentials of —1.0 to —1.5 volts is unlikely provided cathodic protection is continuous. But if the current were cut off, the highly polarized parts would be strongly anodic and would discharge current to the remainder of the system. Pitting and other corrosion attack would result if current interruptions were frequent.

Installation Test Results

Tests conducted subsequent to the installation of the duct anode cathodic protection system were very gratifying, inasmuch as they indicated that the sheath corrosion could be controlled when the anode currents have been adjusted to the requirements of the various duct banks as determined by duct surveys. Current requirements were in the order of 1.5 ma per ft of duct. Tests made during the period when individual anodes (operating at approximately 2-3 amp/anode) were employed for protection showed positive cable-to-slug potentials in about 50 percent of a particular duct run, but a duct-anode current of 450 to 500 ma in a 390 ft duct bank produced cable-to-test-slug potentials negative throughout the duct, and potentials equal to or exceeding the criteria of —150 to —200 mv in nearly two-thirds of the observation. A subsequent adjustment to a feeder increased the cathodic protection current to 615 ma. Protection is considered satisfactory with the increased current. Variations in the cathodic protection currents result from neutral current and voltage variations in the very lightly loaded 125/250 volt d-c distribution system, and have no significant influence on cable protection.

Zinc Cells

High voltages can be developed at locations of electrical discontinuity on underground metallic structures during time of system disturbance on electric power systems, or during time of lightning discharge. Induced voltages can be developed on well-coated pipelines which parallel electric transmission lines, particularly during time of lightning storm or fault conditions. The pipeline is, in effect, a single-turn secondary of an air-core transformer in which the electric power line is the primary.

The induced voltage in a pipeline is dependent upon the exposure which is a function of the length and separation of the systems where they are proximate, the magnitude of the fault current, the coating resistance and the soil resistivity.

In the case of bare pipelines, the secondary of the air-core transformer is effectively short-circuited, and the induced voltage is consumed by impedance drop, so that there is no appreciable voltage-to-ground on the pipeline. In the case of well-coated pipelines the distributed resistance-to-earth is high, and a substantial portion of the induced voltage appears as a voltage-to-ground on the pipeline inasmuch as it is comparable to an open-circuited secondary in the air-core transformer.

Distributed galvanic anodes along the pipeline in the exposure area will reduce the resistance-to-earth of the pipeline and will also provide cathodic protection. They could be installed in groups along the pipeline, and will provide a path for induced currents to leave the pipeline without danger of arcing or burning.

Zinc cells provide a convenient method of supplying a path for discharge of induced currents without short-circuiting insulating joints installed for cathodic protection purposes. A typical grounding cell consists of two anodes installed in the same backfill, closely spaced, but insulated from one another. One of the anodes is connected to the protected pipeline, and the other is connected to the unprotected side of the insulating joint. The anodes are secured in their relative positions by means of insulating spacers and tape bindings.

The resistance between the zinc anodes is substantially independent of the soil resistivity in which they are installed, and is a function of the spacing and resistivity of the backfill mixture. Thus, the impedance to 60 cycle a-c of a cell consisting of two 2-in. sq x 5-ft long anodes spaced 0.5-in. apart in a backfill of 50 percent hydrated gypsum and 50 percent bentonite clay is about one ohm. There is a cathodic polarization effect on the anode that is connected to the protected side of the insulating joint, such that d-c voltages of approximately 0.5 volt can be maintained between anodes without appreciable current flow. The net effect is equivalent to providing a high-resistance path to d-c. The cell described would be rated to carry a 1,000-amp fault current without exerting serious short-circuit stresses in the cell. Additional fault current capacity can be provided by installing 3-anode, 4-anode, or 6-anode cells as required. Additional cells could be installed in parallel if required.

Experiments are being conducted on cells of materials other than zinc, and of different materials for the anodic and cathodic portions of the cells. They have application also across insulating joints in lead-sheathed cables and at terminals of pipe-type cables, installed between the cable pipe and the transformer neutral.

Well-Type Ground Beds

Where right-of-way is not available, or where it may be desirable to introduce cathodic protection current directly to shielded areas, the well-type ground bed can be an effective tool. Well-type ground beds of various designs have been installed to meet specific conditions. One of the earliest dates back to 1941 when an abandoned 6-in. water-well casing was used to protect the entire gas distribution system in a small town in Mississippi. Inasmuch as the distribution pipe was well coated, the current requirements for protection were but 3 to 4 amperes. The ground bed consisted of the aforementioned water well casing which was filled with coke breeze. The coke breeze was installed to keep the ground bed electrically continuous should the casing become segregated from non-uniform current discharge.

An installation of a bare casing in West Texas operated from 1950 to 1956 without backfill. In this case the soil resistivity, down to about the 50-ft depth, was high, but beneath the 50-ft depth, low soil resistivity was encountered. Approximately 30-amp cathodic protection current discharged from beneath the 50-ft depth (total casing depth about 600 ft). The casing segregated in 1956, at a low-resistivity stratum, but was restored to useful service by filling the pipe with coke breeze and graphite anodes.

Another early well-type ground bed installation was used to supplement the groundbeds installed in salt water to provide current to the underground plant in a cooperative cathodic protection installation in the Miami business district. A 50-amp well-type installation using an abandoned water well casing has been in use since about 1946.

When the geologic formations will permit, deep-well installations without casing are desirable in the interests of constructing economical well-type ground beds. Figure 1 illustrates an open-hole type deep-well ground bed. The two looped header cables shown are considered desirable, with anodes connected to alternate riser cables. This arrangement provides reasonable assurance of continued operation, even though a riser cable may be damaged, and consequently part, because of current discharge. Natural graphite flakes are a preferred backfill medium because they do not float, as some sizes of coke breeze do. Limed coke breeze is not desirable because it cements together and can cause gas blocking deep in the well. No cases of gas blocking have occurred with natural graphite that will pass through a 1-in. mesh and be retained on a ⅛-in. mesh. Such material has an apparent density of about 80 pounds per cubic foot.

If the top portion of the hole is cased, it may be desirable to insulate a portion of it. Plastic tape applied to the casing before installation has been found effective for this purpose. Of course the steel must be clean, and the use of a primer under the tape will enhance the bond.

Cannister-type deep-well ground beds are illustrated in Figure 2. They find application in uncased drilled holes in unconsolidated formations that can be held open with drilling mud. The cannisters consist of galvanized corrugated culvert having expanded metal bottoms and hardware-cloth top covers, filled with graphite, silicon-iron, or other suitable impressed-current anode material in coke backfill, coupled together with standard band couplers.

The holes are drilled 25 to 40 ft

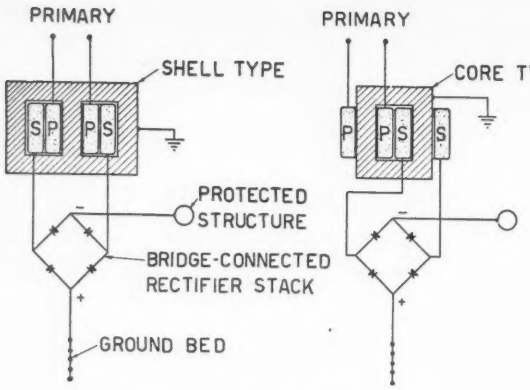


Figure 3—Cross-section of rectifier transformers.

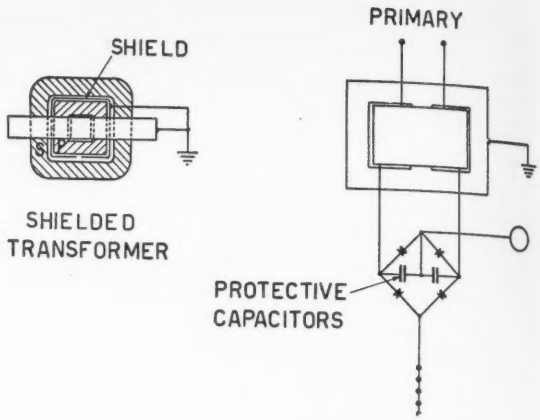


Figure 4—Surge protection for bridge-connected rectifier stacks.

overdepth to provide a catch space for loose or sloughed material, or for the sinking weight if required. The overdepth required can be determined by the extent of loose strata encountered while drilling. It is considered desirable to require the driller to hold open the hole and to circulate mud for one or two hours after making the required depth in order to remove loose sand.

The cannisters are installed by sinking the preassembled string held by a crane into the mud in the uncased hole. If there is a slight amount of bridging in the hole, the cannisters may be carefully spudded in, but if bridging is serious, an additional sinking weight may be required. The sinking weight can consist of 10 ft of scrap 10-in. or 12-in. pipe filled with junk metal or concrete. The extent of bridging in the hole can be tested by running a 10 ft piece of 10-in. or 12-in. pipe having open ends in and out of the hole.

A piece of Transite pipe open on each end installed in coarse roadway stone or broken concrete from the top cannister to grade elevation will provide a gas vent for the ground bed.

Well-type ground beds can be installed to provide local sources of cathodic protection current in areas shielded from remote ground beds, or if installed sufficiently deep, provide "remote" sources of protection current. They may also be used for protection in areas where it is desired to protect structures by change of soil potential, rather than by changing the potential of the structure to remote earth. In such cases the ground bed may be brought close to grade elevation, rather than by installing the effective top of the deep well bed at some depth.

Protection at Shielded Areas

Buried steel piping lying under steel-reinforced concrete mats and between concrete piles is highly shielded from cathodic protection current originating from a remote source. In such cases concrete coating will simplify the problem of protecting pipe in shielded locations. Steel encased in high-quality concrete is not subject to corrosion, except possibly at breaks in the coating, because steel in concrete is cathodic to bare steel. Pipe exposed at small cracks can be effectively protected by means of deepwell-type groundbeds installed in the shielded areas. These can be designed to provide protection by change of pipe potential with respect to local soil, or by changing the local soil potential with respect to remote soil, as indicated by the parameters of the case in question.

Rectifiers Surge Protection

The numerous failures that have been experienced recently with silicon rectifiers may be caused by surges on the power lines rather than by surges on the d-c side of the rectifier. It is possible that the surges which cause the failures result from lightning rather than from switching surges or other system disturbances.

In Figure 3 are shown typical cross sections of shell-type and core-type low-voltage rectifier transformers. In the usual construction (shell-type) the secondary is wound over the primary without an electrostatic shield between the windings. When there is a lightning disturbance on the a-c system, a high-voltage surge may take the form of a sharp peak of very short rise time followed by a reduction of voltage at a rate much smaller than the rate of rise. Successive peaks may occur, of variable transient characteristics. For convenience, an approximation may be made by considering the sharp peak as one half cycle of a high-frequency current. This current will enter the transformer on both primary conductors in parallel, seeking a path to ground.

One possible path is through the capacitance between the primary winding and the grounded core, and the other path is through the capacitance between the primary and secondary windings, then through the silicon diodes to ground. If the voltage stress on the diodes is greater than the peak inverse voltage (PIV) rating of the diodes, they probably will fail.

In the core-type of transformer construction, the capacitance between primary and secondary is small, and most of the surge current would pass from the primary to the grounded core through their capacitance.

The shell-type transformer can be made suitable by installing a grounded shield between the primary and secondary as illustrated in Figure 4. The shield can be a copper mesh or sheet, but it must not form an electrically continuous loop or it would act like a short-circuited turn. If the ends of the shield overlap, the ends must be insulated from one another. If a lightning surge hits such a shielded transformer, two paths to ground are offered through capacitance between the primary and the grounded shield or through capacitance between the primary and the grounded core. The surge will not reach the secondary winding in such a shielded transformer.

If the lightning effect described is the cause of silicon diode failures, bridge-connected rectifier diodes in service can be protected by installing two capacitors across the transformer secondary, and connecting the midpoint to the rectifier negative terminal, as indicated in Figure 4. The capacitors will permit the high effective frequency lightning-induced spit to go to ground via the pipeline, which will normally be the best available ground connection.

As an example of some of the considerations involved in calculating the desirable size of capacitors, assume a lightning induced surge of 10 microseconds duration, which is equivalent to a frequency of about 50,000 cps. If two 50-mfd capacitors are employed, their capacitance to ground will be 100-mfd because they are in parallel. At 50,000 cps the impedance of the combination is approximately 0.03 ohm. A 1000-amp spit would then cause an impedance drop of only 30 volts across the capacitors and diodes, which is below the lowest PIV rating normally used, 50 volts. During normal operation of the rectifier, the capacitor would, in effect, be connected across the transformer secondary during each half cycle (the other is short-circuited by the conducting diode). At 60 cps, the impedance would be approximately 50 ohms. If the trans-

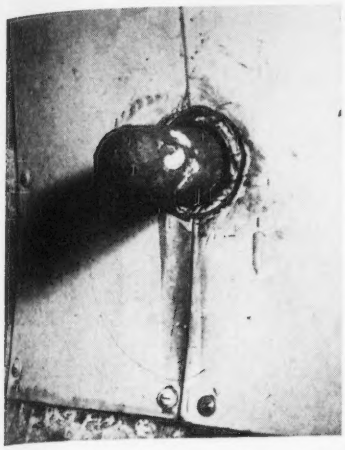


Figure 5—Lead-silver-antimony condenser anode.

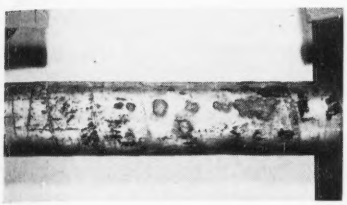


Figure 6—Stray current from welding operation caused perforation of this 2-inch diameter aluminum pipe. This plastic tape coated pipe, used in a power plant, failed in only 90 days.

former were set on the 15-volt tap, this would result in a current of about 0.3 amp.

It is believed that the use of shielded transformers provides the most satisfactory and economical method of protecting new units containing silicon diodes.

Condenser Water-Box Corrosion

Corrosion in condenser and heat-exchanger water boxes is accelerated by the use of dissimilar metals, the use of which often is necessary because of mechanical considerations. For example, steel galvanically coupled to brass, Muntz Metal, copper, or stainless steel will corrode faster than it would if it were alone in the corroding medium. The noble metal connected to the steel will corrode at a slower rate than it would if it were alone in the corroding medium. The galvanic cell formed from connection of dissimilar metals in a condenser is in such direction that current flows from the steel, or cast-iron, water box and cover through the circulating water to the tube sheet and tube ends, and back in the metallic circuit to the steel.

Reduction of corrosion in condenser water boxes can be accomplished by simple rules regarding their painting:

1. When the condenser water box is steel or cast iron and the tube sheet and tubes are brass or other copper alloy, the water box should not be painted or coated. Exceptions occur when water boxes are cathodically protected, or when zinc-rich paint is used.

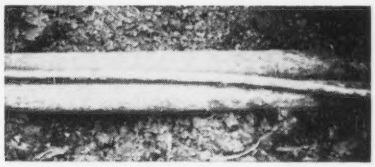


Figure 7—Copper and ferrous piping adjacent to each other.

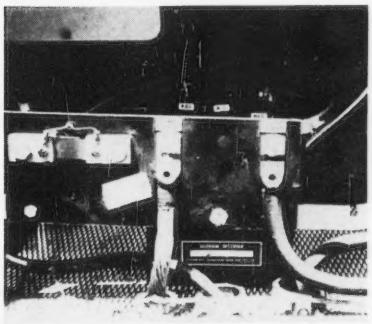


Figure 8—Improperly connected rectifier. The positive output terminal is marked "Ground Bed" and the negative output terminal is marked "Pipe."

2. Painting the tube sheet and tube ends will reduce the galvanic discharge from the ferrous water box and cover, and will help protect the tube ends from corrosion.

When an insulating coating is applied to a condenser water box, the galvanic discharge is concentrated at pinholes or breaks in the coating and accelerated pitting occurs at those locations. The corrosion products formed under the coating destroys the bond, undermines the coating, and shortens its life.

If the steel water box is left bare and the brass tube sheet and tube ends are coated, the corrosion current is reduced just as effectively as when the steel water box is painted. The current that then discharges from the water box results only in superficial corrosion of the steel if the resistivity of the water is not low. As the conductivity of the cooling water increases to that of salt water, the desirability increases also of installing supplementary cathodic protection to prevent local action cells.

Another advantage to the practice of painting the tube sheet and tube ends rather than the water box is the protection afforded the tube ends. In this case, the tube ends receive mechanical protection from the paint and greatly increased electrical protection from the corrosion current. Since the total exposed area of the tube sheet and tube ends is reduced by the paint (small breaks in the coating being the only exposed areas), and the magnitude of the corrosion current is substantially the same as when the water box was painted, the current density on the tube ends and tube sheet is greatly increased. Because the current is collecting on the tube sheet and tube ends, the effect is to reduce corrosion and erosion of these parts as a result of the current. Inasmuch as a set of tubes might cost ten times as much as a water box and cover, there is no doubt that this is the desirable method of painting.

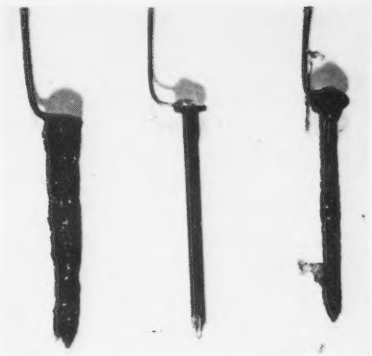


Figure 9—Three bare nails. The nail shown in center is a new one; the nails to left and right were exposed to New York City tap water.

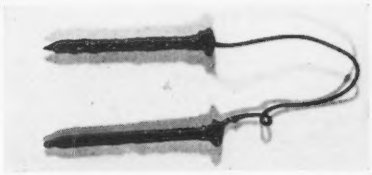


Figure 10—Coupling of bare nail (bottom) to nail with zinc-rich paint having a plasticized polystyrene binder.

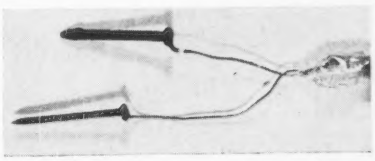


Figure 11—Coupling of bare nail to nail with zinc-rich paint having a catalyzed epoxy binder.

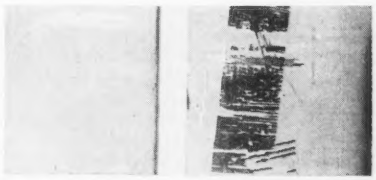


Figure 12—Effect of surface preparation on adhesion of chlorinated rubber base zinc-rich paint. Steel sample at left was sandblasted while sample at right was polished.

If the water box is cast iron instead of steel, corrosion will take the form of graphitization. When this phenomenon has progressed sufficiently, the direction of the galvanic cell reverses, and corrosion of the brass tube ends is accelerated.

The use of cathodic protection as a substitute for painting of condenser water boxes, tube sheets, and tube ends should be considered. Cathodic protection can be designed to control corrosion in a condenser water box and to reduce the corrosion-erosion effect at tube ends. Erosion resulting from the abrasive effects of suspended particles in the water,

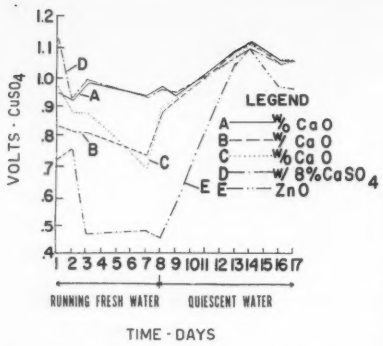


Figure 13—Galvanic potentials of zinc-rich paint in New York City tap water.

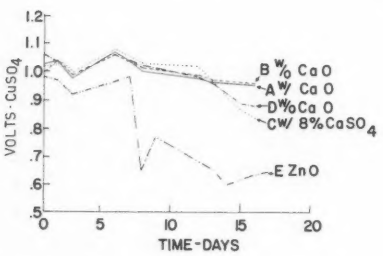


Figure 14—Galvanic potentials of zinc-rich paint in salt water.

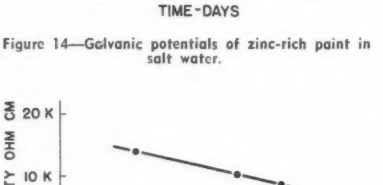


Figure 15—Resistivity of zinc-rich paint.

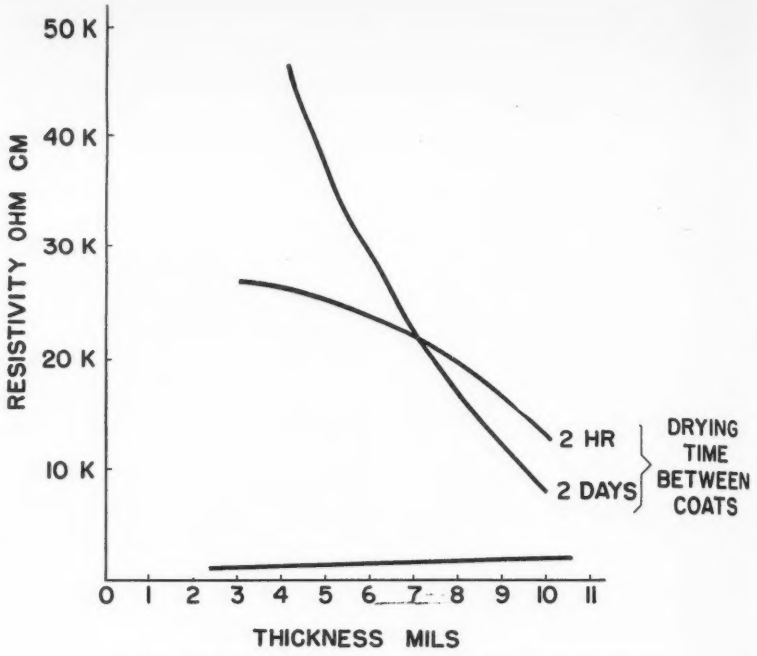


Figure 16—Effect of drying time between coats on the resistivity of zinc-rich paint.

or of cavitation effects, is greatly reduced when galvanic corrosion is controlled.

The application of cathodic protection to water boxes has been used successfully in condensers using salt, brackish, and fresh waters.

Anodes of various materials have been used. High silicon iron is quite satisfactory for fresh waters, and Durichlor or lead-silver-antimony are suitable for salt water applications. The lead-silver-antimony alloy (1 percent silver, 6 to 8 percent antimony, balance lead) has only recently been available in the United States, but has had long service as an anode in alkali-chlorine processing. Also it has been in use in England for cathodic protection for several years. The anode functions as a low-loss anode by development of a lead peroxide film formed by reaction with chlorine electrolyzed at the anode by high current densities in the order of 5-20 amp per sq ft. The anode is consumed in sea water at a rate of approximately 0.25 lb per ampere per year at an optimum anode current density of 10 amp per sq ft.

A lead-silver-antimony condenser anode is shown in Figure 5. This bullet-shaped anode was in service from March, 1958 to May, 1959 in a sea water electrolyte, discharging 4 to 5 amperes. At the most recent inspection it was in excellent condition, with a lead peroxide layer about ⅛ in. thick. Only a minute amount of lead had been consumed, and the anode dimensions were virtually the same as when the anode was installed (3-in. nominal diameter tapering to a 2.75-in. dia hemispherical nose, total length, 7.75 in., integrally cast on ¾-in. dia steel stud for mounting, which must be insulated from the water box). The rectangle in back of the anode is a linen-base bakelite sheet mounted on the wall of the water box, whose purpose is to reduce the high current density that would otherwise obtain adjacent the anode.

Stray Current Discharge

Probably the most common association of corrosion and the discharge of electricity to an electrolyte from a metal surface is the discharge of stray current from pipelines and cable sheaths associated with the operation of traction systems. Through painful experience the lessons have been learned concerning the control of stray current in the earth from these sources. Yet in Figure 6 is shown an example of stray current electrolysis with the modern touch. Shown is a 2-in. dia aluminum pipe at a power plant that had a plastic tape coating applied in accordance with modern specifications and techniques. But stray currents from welding operations during construction of the plant were not controlled. The pipe shown was perforated within 90 days of its installation although it was planned for a minimum life of 25 years. It could have readily achieved the planned life if greater care had been exercised in the control of stray current.

In another instance a leak occurred in a 2-in. service water line under a concrete slab about six months after installation. Another leak occurred in the same line four years later. Both leaks resulted from external corrosion. The pipe section was replaced with plastic pipe. Examination of a section of pipe removed from the area of the failure showed many deep pits on the external surface. The location of the failure was shielded by the proximate reinforcing steel in the concrete slab, and the location of the pipe in reference to other piping. The penetration of the pipe wall six months after installation would be very unlikely if soil corrosion were the only source of attack.

When the path of the direct current used for welding is not metallically continuous, corrosion of the structure being welded, or some part of the structure used for the ground circuit (depending upon the polarity used) may be expected.

Electrolytic corrosion of steel can result in a loss of metal of 20 lb per ampere per year. It can be seen from this that even if only a small part of the welding current is allowed to stray, serious damage can occur where many welding machines are used. If, for example, the net current from a welding substation is 750 amperes from simultaneous arcs, the loss of metal from stray current discharge could be as high as 1.7 lb per hour. A small fraction of this loss would be sufficient to cause deep pitting or penetration of a pipe wall. Pitting can occur in an extremely short time if the pipe is coated, because

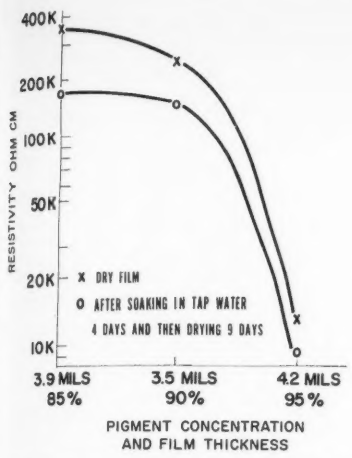


Figure 17—Resistivity of zinc-rich paint as a function of pigment concentration.

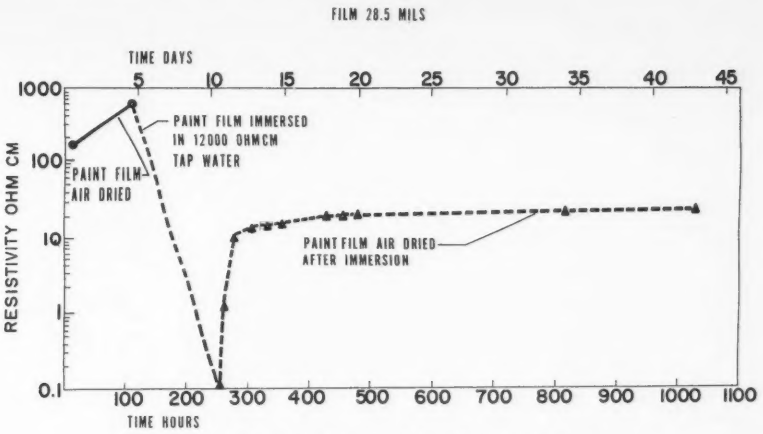


Figure 18—Forty-three day test of zinc-rich paint resistivity.

corrosion is concentrated at pinholes in the coating.

The coating faults in the plastic tape coating on the failed aluminum pipe of Figure 6 resulted from workmen walking on the pipe prior to backfilling, and from cleaning shovels by striking them against the coated pipe. Recording charts were obtained which correlated potentials observed with welding operations.

Great reduction of stray current can be effected by grounding the welding machine to a structure that is metallically continuous with the work.

The adjacent copper and ferrous piping shown in Figure 7 recently were observed in an excavation. It would be almost impossible to supply sufficient cathodic protection current to mitigate a galvanic cell as strong as this with anodic and cathodic metals interwoven. This condition occurred was noted notwithstanding a separation requirement of two feet between ferrous and nonferrous structures.

The rectifier shown in Figure 8 was observed to be improperly connected. The manufacturer marked the positive output terminal, Ground Bed, and the negative output terminal, Pipe. To an electrician at a generating station the word ground means the station ground, and ground bed merely amplifies this meaning in his mind. Inasmuch as the one terminal is to be connected to the station ground and there is no connection made to any pipe at the rectifier location, it is understandable how the mistaken connection can be made by the electrician in his innocence. Needless to say, such connections are worse than no corrosion control installations at all, for they can cause corrosion of the buried metallic structures if uncorrected. The manufacturers are requested not to so mark any rectifiers intended for use at electric utility installations.

Zinc Rich Paint

The value of zinc dust as a paint pigment has long been known, and has been in use for more than a century. Zinc dust paints have achieved importance in industry during the past twenty years. U. R. Evans and J. E. O. Mayne have done much of the original development work on zinc dust paints at Cambridge University.

Recently, considerable attention has been given to zinc-rich paints, which generally contain 90 to 95 percent zinc, by weight, in the dried film. There are two general classes of zinc-rich paint, called organic or inorganic, depending upon the binder. The commonly used inorganic zinc-rich paint is based upon the development of zinc silicate, either by baking or by chemical conversion. Outstanding performance has been achieved with such paints. (Very recently, inorganic zinc-rich paints have been marketed which do not require baking or separate application of a curing solution to effect conversion).

The most popular binders for the zinc pigment of the organic zinc-rich paints are chlorinated rubber, polystyrene, and epoxy resins, although others can be successfully employed. Results are not identical with the various formulations being marketed.

The zinc particles of the zinc-rich paints contact one another and the substrate with the small percentage of binder cementing them together. If the zinc dust concentration is sufficiently high, cathodic protection of the steel can be effected as with galvanizing.

The advantages of zinc-rich paint are obvious, for it can be used anywhere galvanizing will give good service. Also, because the corrosion product of the paint in providing protection in the presence of moisture is zinc hydroxide, this also will provide inhibition of corrosion. Rust creep does not develop under zinc-rich paint at pinholes, holidays, or abrasions, as occurs under organic films. Ease of touch-up if done before the protective effect is exhausted and before major surface preparation is required makes zinc-rich paints desirable maintenance coatings without supplemental top coats. Disadvantages to the use of zinc-rich paint are (1) weight of the paint because of the heavy pigment which requires packaging in small units, (2) settling of the pigment, which varies with the binder and suspending agent that is employed, and (3) development of gas in the package from evolution of hydrogen by reaction of the zinc with acidity in the vehicle in the presence of moisture. Some zinc-rich paints are packaged in two parts and must be mixed prior to application. This is especially true of catalytically cured binders, such as the epoxies.

The adhesion of zinc-rich paints to steel tends to improve with the passage of time. The adhesion to copper alloys has been found generally to be poor. Some formulations have remarkable abrasion resistance. A failing of zinc-rich paint is the blistering that occurs upon immersion in sea water. This has been observed to be more pronounced with polystyrene binders than with chlorinated rubber.

In order that some evaluation of the many claims for zinc-rich paints might be made, several simple tests with nails were conducted. Bare steel nails were equipped with pigtails and were cleaned. They were coated with various formulations of zinc-rich paint, and immersed in New York City tap water alone or coupled to a bare nail. Figure 9 illustrates the corrosion that occurs in one year on an uncoated bare nail. The center nail is a new one shown for comparison.

Figure 10 shows the results with a zinc-rich paint having a plasticised polystyrene binder coupled to a bare nail after one year in tap water. There was ½ inch of rust in the bottom of the container at the conclusion of the test.

Figure 11 shows a zinc-rich paint having a catalyzed epoxy binder coupled to a bare nail in tap water for six months. This paint gave quite satisfactory results, for no rusting of either nail developed.

Various brands of zinc-rich paints having chlorinated rubber binders were tested. Two paints gave excellent results, whereas a third type had ½ inch of rust in the bottom of the container at the conclusion of the test.

A test showing the improvement in adhesion that can be realized by adequate surface preparation is illustrated in Figure 12. The steel sample on the left was sandblasted, and the sample on

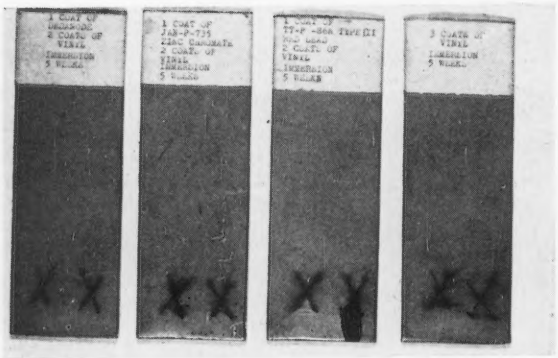


Figure 19—Specimens immersed for five weeks in demineralized water. Panels, left to right: one coat of zinc-rich paint with two coats vinyl top coat; one coat zinc chromate with two coats vinyl top coat; one coat red lead with two coats vinyl top coat; three coats vinyl.

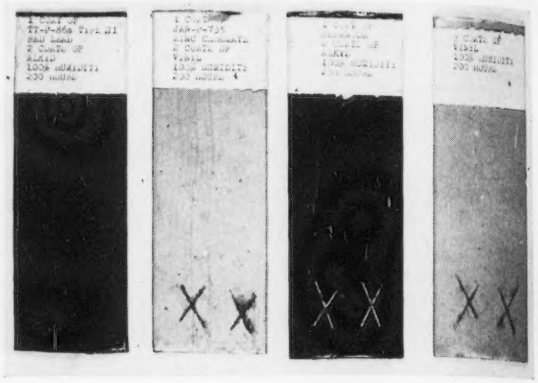


Figure 20—Results of exposure of coated samples to 100 percent humidity. Samples, left to right: prime coat of red lead with two top coats of alkyd; prime coat of zinc chromate with two top coats of vinyl; prime coat of zinc-rich paint with two top coats of alkyd; three coats of vinyl.

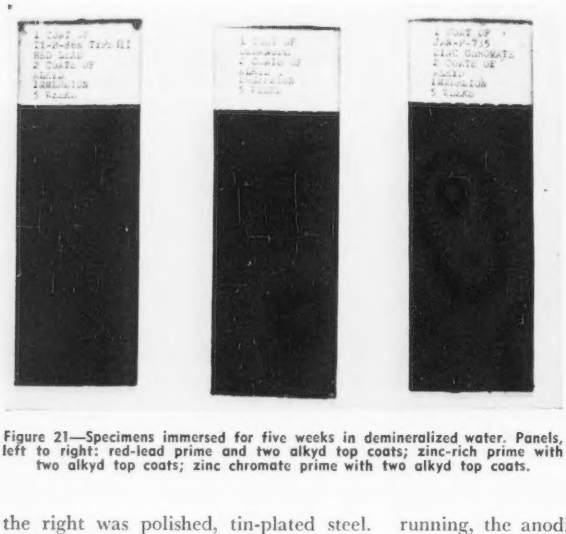


Figure 21—Specimens immersed for five weeks in demineralized water. Panels, left to right: red-lead prime and two alkyd top coats; zinc-rich prime with two alkyd top coats; zinc chromate prime with two alkyd top coats.

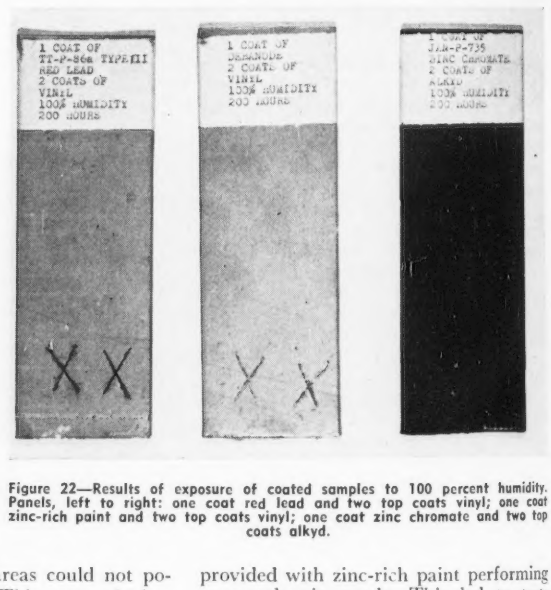


Figure 22—Results of exposure of coated samples to 100 percent humidity. Panels, left to right: one coat red lead and two top coats vinyl; one coat zinc-rich paint and two top coats vinyl; one coat zinc chromate and two top coats alkyd.

the right was polished, tin-plated steel. Each plate was then coated with chlorinated-rubber base zinc-rich paint. A scratch through the paint to the underlying steel was scored on each specimen, and then a piece of transparent cellophane pressure-sensitive tape was pressed over the score with a roller, and then quickly torn off. The results show that the sample on the right, on the tin plate, not only lost paint at the edge of the score, but that much of the coating under the tape was removed. The sandblasted surface held its coat of paint.

Tests that were performed to ascertain the galvanic effects of zinc-rich paints in New York City tap water are recorded in Figure 13. In these tests paints whose zinc pigment contained lime, pigment from two different manufacturers—one of whom produces zinc dust from virgin metal and the other of whom produces it from galvanizing dross—were checked along with a formulation containing 8 percent $CaSO_4$ and a sample of 80/20 zinc-dust/zinc-oxide paint with a phenolic vehicle. All the zinc-rich paints had a chlorinated-rubber vehicle. While the water was running, the anodic areas could not polarize the cathodes. This water had a resistivity at the time of test of 18,000 ohm-cm. During the year, its resistivity ranges from 12,000 to 20,000 ohm-cm, depending upon quantities drawn from different supply sources. When the water was quiescent, the cathodes polarized readily. Similar tests in quiescent salt water are illustrated in Figure 14.

It is interesting to note that there is little practical difference in any of the pigments, insofar as the resulting galvanic potential is concerned, in the case of the zinc-rich formulations. Variations resulting from oxygen content of the water are of much greater importance. In high-resistivity tap water, the potential of the 80/20 zinc-dust/zinc-oxide paint approached that of zinc metal, but in salt water, there was insufficient contact between pigment particles to provide enough current to polarize the substrate to the potential of zinc. Apparently the fresh water sample had very few holidays.

The results of the foregoing tests indicated that cathodic protection can be provided with zinc-rich paint performing as a galvanic anode. This led to tests on resistivity of the paint film, the results of which are outlined in Figures 15-18. All these tests were on chlorinated-rubber base zinc-rich paint. Samples were prepared on glass, and the dimensions carefully measured. Leads for electrical tests were anchored in the paint film with additional zinc-rich paint.

It is observed that the resistivity drops as the film thickness increases. This would not occur with a true metal. It is believed that with thicker paint films, chance for additional contact between particles increases, and the resistivity is lower.

A test was conducted to learn whether variation in the drying time between coats would change the resistivity of the final film. If the surface developed an oxide film upon exposure to the air, the resistivity of the surface layer would be higher than that of the underlying paint. This is shown in Figure 16, but becomes of less importance as the film thickness increases. The line on the bot-

Figure 23—Failure of paint on exterior surface of water storage tank.

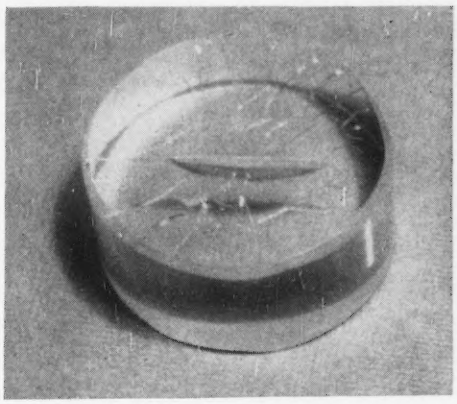


Figure 24—Zinc-rich paint mounted in Lucite for microscopic examination.

tom of the figure shows the resistivity when the film is wet with salt water. This indicates the porosity of the paint because of the greatly lowered values obtained on the wet samples.

The plot of resistivity against pigment concentration, as shown in Figure 17, shows that for a chlorinated-rubber binder, the pigment concentration should be in excess of 90 percent. Soaking the films in tap water and then permitting them to dry reduced the resistivity by causing some of the pigment to corrode to zinc hydroxide, expand, and fill some of the void between pigment particles.

An interesting experiment is shown in Figure 18. A large sample was prepared on a glass sheet by applying nine coats to form a film 30 inches long x 5.75 inches wide x 0.0285 inch thick. Current electrodes were anchored at the ends of the paint film, and potential terminals were anchored 20 inches apart, 5 inches from the ends. It is noted that at the start of the test the film had a resistivity of 160 ohm-cm which increased as it air dried almost five days to 650 ohm-cm. When soaked in tap water for five days, the resistivity dropped to 0.1 ohm-cm, and upon drying increased to 28 ohm-cm, which is about 18 percent of the value at the start of the test. It did not increase above that value from the 18th to the 43rd day of the test, when measurements were discontinued.

Comparisons with Conventional Primers

In order that zinc-rich paint might be compared as a primer with commonly used standard primers, tests were conducted at a commercial laboratory on chlorinated-rubber base zinc-rich paint, red lead conforming to Federal Specification TT-P-86A, Type III, and zinc chromate conforming to Specification JAN-P-735, with a standard vinyl formulation as a control. The panels were hot-rolled steel, shot blasted and coated on one side only. Spreading rates for the paints were 350 sq ft/gal for zinc-rich paint and 400 sq ft/gal for all other paints. Samples were immersed in demineralized tap water, and separate samples were exposed to 100 percent relative humidity (tap water) for 200 hours. Each of the samples was scored to expose the steel substrate prior to testing. The samples were rated at the conclusion of the test on a scale of 1 to 10 for each of the following:

Blistering
Rusting
Rust Staining
Creep
Loss of adhesion of top coat

The rating code was:

10	No effect
9+	Trace
9	Very slight
8	Slight
6	Moderate
4	Considerable
2	Severe

In Figure 19, are shown specimens which were immersed for five weeks in demineralized water. From left to right, they have one coat zinc-rich paint with two coats vinyl top coat; one coat zinc chromate with two coats vinyl top coat; one coat red lead with two coats vinyl top coat; and three coats vinyl. At the conclusion of the test, the cumulative score for these samples was 50, 31, 25 and 43 respectively.

Figure 20 shows the results of exposure to 100 percent humidity for samples coated as follows (from left to right):

Prime coat of red lead with two top coats of alkyd

Prime coat of zinc chromate with two top coats of vinyl

Prime coat of zinc-rich paint with two top coats of alkyd

Three coats of vinyl

The cumulative score at the conclusion of this test was 45, 37, 49 and 41 respectively. The sample with the zinc-rich prime was white in the scored area.

In Figure 21, are shown samples coated with a red-lead prime and two alkyd top coats; a zinc-rich prime with two alkyd top coats; and a zinc chromate prime with two alkyd top coats. After five weeks immersion in demineralized water, the samples were scored respectively 48, 50 and 42.

In Figure 22, are shown samples which were exposed to 100 percent relative humidity for 200 hours, coated as follows: one coat red lead, two top coats of vinyl; one coat zinc-rich paint, two top coats of vinyl; one coat zinc chromate, two top coats of alkyd.

These samples were scored 40, 50 and 39 at the conclusion of the test. The zinc-rich coated sample was white in the scored area and the zinc chromate prime sample had a yellow stain in the scored area.

The general observation from the series of tests is that zinc-rich paint performed as well, or better, than conventional priming materials.

Excellent experience to date has been obtained with zinc-rich paint used either with or without top coats in accordance with the requirements of the exposure. Two failures that were conspicuous because they were unusual to the author's experience occurred on elevated water storage tanks in the Southwest. The steel was acid pickled and shop coated with zinc-rich paint. After erection and test for tightness, a touch-up coat of zinc-rich paint was applied to abraded or damaged spots, and two coats of aluminum paint, conforming to Steel Structures Paint Council Specification SSPC-Paint 100-SST, were applied to the exterior surfaces. One field coat of zinc-rich paint was applied to the interior surfaces. The tank and tower steel was on the jobsite at least four months before erection. The construction log shows field painting was carried on during hot, cloudy, and very dry weather.

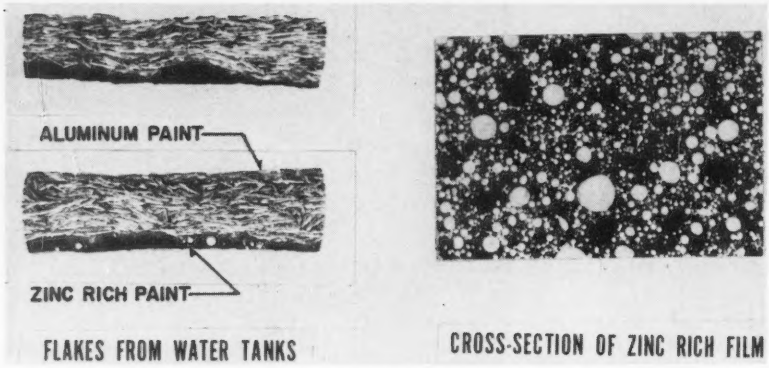


Figure 25—Cross section of paint flakes in reflected light. Approximately 185X.

Figure 26—Organic zinc-rich paint freshly stirred (left) and after standing three weeks (right). Approximately 155X.

Figure 23 shows a close-up of the failure observed on the exterior surfaces. The pieces of peeled paint were numerous and large in size; for example, a piece 8″ x 12″ could easily be removed by starting a loose end. The peelings were of aluminum paint containing numerous pinholes apparent in most of the sample, but with a dark coating on the back which was apparently a thin mottled layer of zinc-rich paint. The zinc-rich paint remaining on the steel under the peeled area appeared to be in good condition. Freshly exposed surfaces were slightly darker in color or shade than where aluminum had peeled earlier. White spots, apparently zinc oxide, were noted on the zinc-rich paint where aluminum pieces were peeled off for samples, and such spots evidently matched pinholes in the aluminum. Formations of white zinc corrosion product were evident in many places, ranging from an occasional heavy deposit to a wider spread white "bloom". Obviously, the zinc was active in the peeled areas.

In order that further information might be obtained, samples of the peeled paint were submitted to the paint manufacturer for analysis. He consulted with the pigment manufacturer whose laboratory examined the paint chips by a low angle X-ray reflection method. No signs of zinc oxide or zinc hydroxide could be detected by the laboratory, and only the X-ray pattern of metallic zinc was observed. This means that if any zinc oxide or hydroxide had formed on the surface of the shop coat of zinc-rich paint, it was not sufficiently dense or thick to cause loss of adhesion of the aluminum paint.

Specimens of the flakes were clamped between Lucite plates and cross sectioned. The cross section was polished and examined in reflected light under a metallographic microscope at a magnification of 250X. Figure 24 shows how a flake prepared from a sample of freshly-mixed zinc-rich paint was mounted in Lucite and polished.

In Figure 25 are shown photographs of the cross section paint flakes obtained from water tanks, and a cross section of standard zinc-rich film. The aluminum finishing paint is readily identified by the appearance of the aluminum flakes embedded in the vehicle matrix. The aluminum paint layers range in thickness from 1.5 to 2 mils, which is normal for the painting system employed. Under the aluminum paint layers, there is a dark layer of material which contains a few zinc pigment particles. This layer is extremely thin and ranges in thickness from about ¼ to ¾ mil, which is only a relatively small fraction of the normal film thickness for the chlorinated-rubber base paint employed (about 2 mils).

The zinc pigment concentration in the thin layers is not normal. A picture of the cross section of a normal layer of this paint is shown on the right of Figure 25 for comparison purposes. There is no doubt that the very sparse population of metallic zinc particles visible in the thin dark layers under the aluminum films (which becomes especially apparent when it is compared with the rather dense population of zinc in the normal coating) would indicate that the zinc-rich paint applied as a shop coat had not been properly stirred. The white spots are zinc metal, some of which are agglomerates because of the low vehicle binder content. It is believed that most of these would be broken down during application. The black spots are not all chlorinated rubber.

Chemical analysis of the flakes confirmed the microscopic analysis and indicated that the zinc concentration was too low for a normal paint film. The results of this examination indicate that the zinc-rich paint was not properly stirred before application and that vehicle with very small pigment concentration was applied to the steel surfaces. The paint manufacturer has subsequently developed a ready-mixed formulation to combat this deficiency that might occur during application.

Comparison of microscopic examination, under reflected light, for films of freshly stirred paint and paint that was allowed to stand three weeks is shown in Figure 26. The similarity of these photographs indicates that the new formulation of ready-mixed paint would avoid the type of trouble experienced on these water tanks.

Acknowledgment

The author expresses his acknowledgment and thanks to The Debevoise Company and to the New Jersey Zinc Company for their assistance in providing samples for tests and for conducting laboratory work. The Subox Company, Amercoat Corporation, Duriron Company, Federated Metals Division of American Smelting & Refining Company, and the Cathodic Corrosion Control Ltd of England also have contributed samples for test purposes.

Any discussion of this article not published above will appear in June, 1961 issue.

Cracking of Low Carbon Steel By Ferric Chloride Solutions*

By MARY BOEHM STRAUSS and M. C. BLOOM

Strauss

Bloom

MARY BOEHM STRAUSS is presently a housewife. Formerly she held a research position in the Corrosion Consultant Staff of the Metallurgy Division of the U. S. Naval Research Laboratory. She received a BS from Bowling Green State University and a PhD in physical chemistry from Michigan State University.

M. C. BLOOM is a consultant in charge of corrosion research in the Metallurgy Division of the Naval Research Laboratory, Washington, D. C. He received a BS in chemical engineering from MIT in 1922. Six years in the paper and petroleum industries were followed by a return to MIT where he obtained a PhD in physical chemistry and worked as a research associate in crystal chemistry and electrochemistry. In 1949 he joined the Naval Research Laboratory as a consultant after several years of private consulting.

Abstract

Aqueous corrosion of mild steel at 316 C is greatly accelerated by low concentrations of $FeCl_3$. This can lead to stress corrosion cracking in plastically deformed areas subject to high stress. Analogous results can be obtained with chloride-bearing slurries of the ferric oxides and hydrated oxides γ-FeOOH, α-FeOOH, γ-Fe_2O_3 and α-Fe_2O_3 or from slurries of these compounds in contact with chloride-bearing solutions. These observations may be significant in connection with boiler operations when substantial amounts of chloride are present. 3.5.3

Introduction

THIS PAPER describes experiments from which it is concluded that mild steel can undergo stress corrosion cracking in $FeCl_3$ solutions at 316 C. Chloride-bearing slurries of the ferric oxides and hydrated oxides γ-FeOOH, α-FeOOH, γ-Fe_2O_3 and α-Fe_2O_3 or slurries of these compounds in contact with chloride-bearing solutions at this temperature can also produce this cracking.

The data were obtained during some studies[1] of the transformation behavior of aqueous slurries of iron oxides and hydroxides when heated in mild steel capsules. Of 11 steel capsules heated with aqueous slurries of γ-FeOOH at 316 C, all 11 developed cracks in the metal and leaked within 6 hours. In some cases capsules heated with γ-FeOOH slurries burst open explosively. The capsules were made from partially flattened steel tubing sealed by welding at the ends.

Figure 1 is a photograph of one capsule which burst in the welded area. The partially flattened edges of capsules are also susceptible to the cracking and Figure 2 shows an example of a burst along the flattened edge of a capsule. This capsule also has deep cracks in the unseparated edge. About 10 percent of the capsules heated at 316 C with γ-FeOOH slurries burst open in the manner shown in these two figures. All others of 90 some odd capsules tested which contained greater than 0.3 weight percent γ-FeOOH developed cracks which penetrated the metal walls and permitted fluid to leak. Analogous capsules containing α-FeOOH, α-Fe_2O_3, γ-Fe_2O_3 or Fe_3O_4 did not develop leaks.

The composition of the steel is shown in Table 1. Some of the changes undergone by a piece of steel tubing during capsule fabrication and treatment at 316 C are shown in Figure 3. In this figure the uppermost diagram is that of longitudinal and transverse cross sections of a piece of one quarter inch diameter, 20 mil wall, mild steel tubing. Before fabrication into capsules, the steel tubing was hydrogen annealed one hr at 875 C, cooled in the hydrogen atmosphere to 60 C and then removed to the atmosphere of the room; subsequently, the tubing was annealed one hr at 875 C in a vacuum furnace maintained at a pressure of less than 10^{-5} mm Hg and cooled to room temperature in the furnace. Chemical analysis of the steel before and after hydrogen annealing indicated that the steel did not undergo decarburization during annealing. Microscopic examination verified this.

The middle diagram of Figure 3 shows cross sections of a formed capsule prior to heating. In the preparation of capsules the tubing is partially flattened to allow for expansion at the elevated temperature. One end is then completely flattened and sealed by welding. The other end is left open for introduction of the slurry. The empty tube is weighed at this point. Solid is then placed inside the tube with a spatula and the tube is again weighed. A few drops of distilled water are introduced with a syringe and the tube is shaken to mix the water and solid. Then with the syringe the tube is filled with water and while the tube is being held upright the open end is completely flattened. A small amount of dilute slurry is forced out during the flattening, but the procedure provides a capsule filled with slurry and containing no air bubbles. The closed capsule is finally weighed to permit computation of the slurry composition and then the unsealed end is welded.

The lower diagram of Figure 3 is that of a capsule which has been heated to 316 C with an aqueous solution or slurry Such a capsule has expanded as a result of hydrostatic pressure which is somewhat in excess of 1550 pounds per square inch at 316 C.

Areas Susceptible To Cracking

Photomicrographs were made from sections cut through the areas susceptible to cracking, that is, the plastically deformed areas at the welds and along the flattened edge. Figure 4 is a typical photomicrograph and shows a cross section through the partially flattened edge of a capsule which was heated with high purity water for four weeks at 316 C. Corrosion has not significantly penetrated the metal in this capsule. In a capsule heated with water for two years the maximum penetration was 2 mils.

Figure 5 shows that the weld region of the capsule heated four weeks with water is unattacked. The weld metal has a martensitic structure which accounts for the darkened regions apparent in Figures 5, 7, and 10.

Figure 6 is a photomicrograph of the partially flattened region of a capsule

* Submitted for publication March 28, 1960.

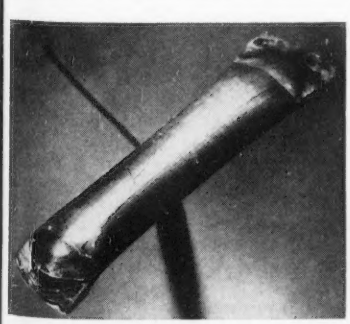


Figure 1—Capsule which burst in the welded area as a result of heating with an aqueous slurry of commercially obtained γ-FeOOH (Approximately actual size.)

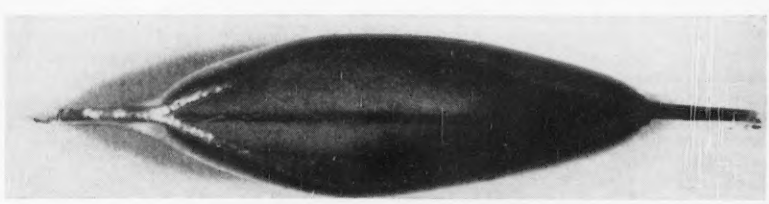


Figure 2—Capsule which burst in the deformed, partially flattened region as a result of heating with an aqueous slurry of commercially obtained γ-FeOOH (Approximately 2.0X).

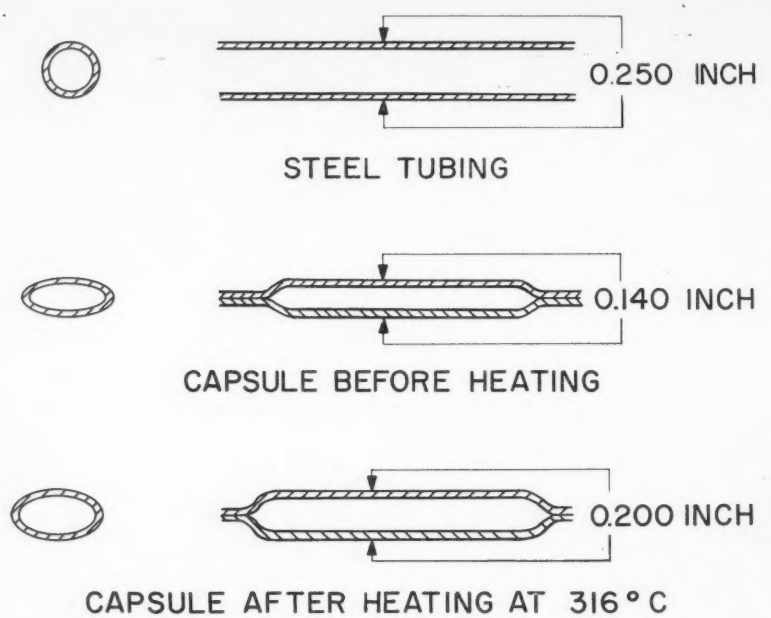


Figure 3—Diagram showing changes undergone by steel tubing during capsule fabrication and treatment at elevated temperature.

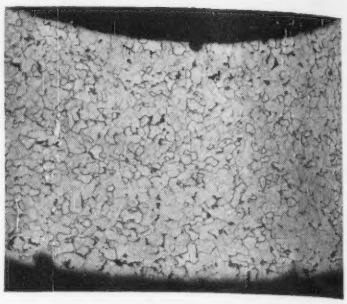


Figure 4—Cross section through the partially flattened edge of a capsule heated with high purity water for 4 weeks at 316 C. Magnification 90X. Etchant: 1 percent Nital.

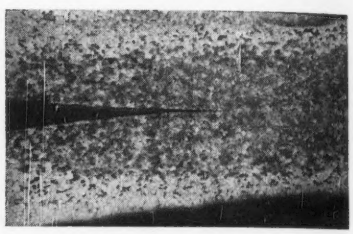


Figure 5—Cross section through the weld in a capsule heated with high purity water for 4 weeks at 316 C. Magnification 37X. Etchant: 1 percent Nital.

treated at 316 C for four weeks with α-FeOOH slurry. There is evidence that corrosion has started. Figure 7, a photograph of the same capsule, shows that the metal was only slightly attacked at the weld junction during four weeks' treatment with α-FeOOH at 316 C.

Figure 8 shows a cross section cut through the partially flattened edge of a capsule heated with γ-FeOOH slurry to the point at which fluid leaked from the capsule as a result of severe cracking. This penetration was produced in many capsules in as short a time as two hours.

Figure 9 shows a similar cross section of another capsule heated with γ-FeOOH. This photograph shows clearly that the cracking is transgranular. The weld area of the same capsule appears in Figure 10. Severe attack has occurred at this point. In those capsules which did not burst, leaks were observed to occur in some cases through a penetration at the weld and in other cases through a penetration in a flattened edge.

Capsules heated with γ-FeOOH slurries do not expand more than do capsules heated with water or other oxide slurries. Therefore, in considering mechanisms responsible for the cracking the possibility seemed unlikely that the cracking could be produced by excessive internal pressure such as a pressure which might result from generation of some gaseous products that could not escape from the capsules. It was demonstrated by experiment that about 4000 psi of hydraulic pressure is required to burst capsules at the welds. That pressure does not produce cracks in the partially flattened edges. This indicated that the cracking process must be associated with corrosion and not with mechanical stress alone.

In order to determine if the attack produced by γ-FeOOH slurries at 316 C is associated with a stress corrosion mechanism, pieces of capsule tubing were flattened in the manner ordinarily used in the preparation of capsules. The partially flattened edges were sliced off the tubing to form trough-like specimens each 1″ long. When these specimens were heated at 316 C in sealed capsules containing slurries of γ-FeOOH the capsules cracked along the stressed, deformed edges, but no cracking or other accelerated attack was evident in the unstressed, deformed edges of the loose specimens inside the capsules, demonstrating that stress corrosion cracking is operative in this attack of mild steel by slurries of γ-FeOOH.

A study made to determine the effect of slurry composition on cracking time showed no relationship between the amount of solid in the slurry and the time of leaking except that slurries containing less than 0.3 weight percent γ-FeOOH did not produce leaking.

Hydrogen Effusion Technique

Corrosion rate data were obtained by the hydrogen effusion technique.[2] In this method the amount of hydrogen effusing through the wall of a corroding steel capsule is continuously measured. In Figure 11 appear typical rate curves for capsules heated with aqueous slurries of γ-FeOOH and α-FeOOH. Rate data for capsules heated with water are shown for comparison. It may be noted that in the case of the α-FeOOH slurries, very high initial rates are reduced to those comparable with water after about two hours. These data correlate well with microscopic examination which showed that capsules heated with α-FeOOH slurries undergo some attack (see Figure 6).

TABLE 1—Analysis of Steel

Constituent	Weight Percent
C	0.09
P	0.017
S	0.032
N	0.007
Mn	0.57
Si	0.07
Cr	0.10
Ni	0.07
Fe (by difference)	99.05

Figure 11 includes data from the first 30 minutes of the rate measurement. In these early minutes when the capsules are coming to temperature and the metal is outgassing, the data are not very reproducible as indicated by the two curves for water. However this figure does show that the amount of hydrogen effusing from the capsules containing γ-FeOOH and α-FeOOH is very high compared to the amount effusing from water capsules. It is a coincidence that the maxima for the capsules chosen as examples containing γ-FeOOH and α-FeOOH nearly coincide. Of the capsules studied these early maxima varied between 20,000 and 50,000 mg/dm²-mo. It was originally thought that these high hydrogen effusion rates might of themselves play the major role in the cracking phenomenon but more recent experiments have indicated that in some caustic solutions the generation of much larger quantities of hydrogen does not produce so drastic a cracking phenomenon.

The accelerated rates in capsules filled with slurries of γ-FeOOH and α-FeOOH suggested that the attack might be due to the presence of Fe (III) ion alone.

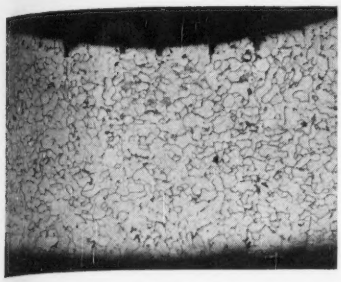


Figure 6—Cross section through the partially flattened edge of a capsule heated with an aqueous slurry of commercially obtained α-FeOOH for 4 weeks at 316 C. Magnification 80X. Etchant: 1 percent Nital.

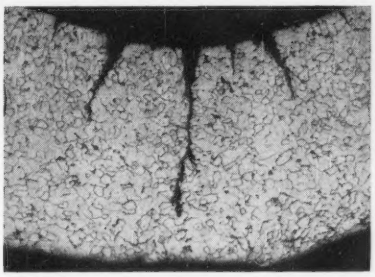


Figure 8—Cross section through the partially flattened edge of a capsule heated with an aqueous slurry of commercially obtained γ-FeOOH to the point at which the capsule leaked. Magnification 80X. Etchant: 1 percent Nital.

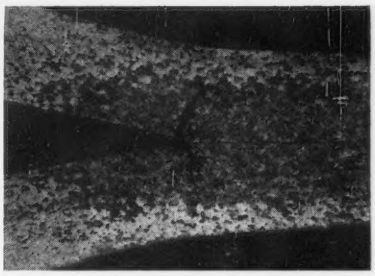


Figure 10—Cross section through the weld in a capsule heated with an aqueous slurry of commercially obtained γ-FeOOH. Magnification 37X. Etchant: 1 percent Nital.

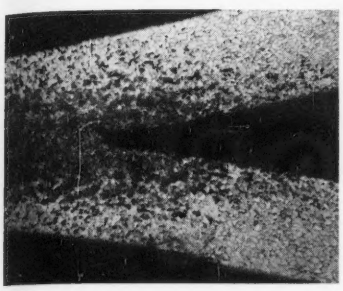


Figure 7—Cross section through the weld of a capsule heated with an aqueous slurry of commercially obtained α-FeOOH for 4 weeks at 316 C. Magnification 37X. Etchant: 1 percent Nital.

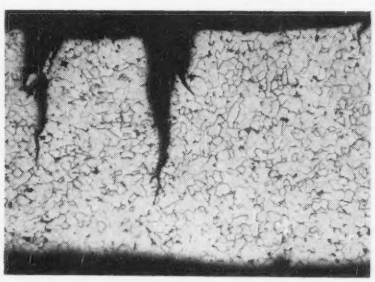


Figure 9—Cross section showing the transgranular nature of the cracking produced in mild steel during heating with slurries of commercially obtained γ-FeOOH. Magnification 80X. Etchant: 1 percent Nital.

Therefore mild steel capsules were filled with 0.001 M solutions of $FeCl_3$, or the equivalent concentration of Fe $(NO_3)_3$, and $Fe_2(SO_4)_3$ to keep the Fe (III) constant. The results of this study are shown in the upper part of Table 3. Only the capsules containing $FeCl_3$ solution cracked indicating that Fe(III) ion alone was not responsible for the accelerated corrosion. This directed attention to the combined effect of Fe(III) and chloride ion. Capsules heated with 0.0001 M.$FeCl_3$ solution were attacked very slightly, but did not leak, while capsules heated with 0.001 M.$FeCl_3$ cracked and leaked within 6 to 15 hours. Capsules heated with 0.003 M NaCl did not crack and this further emphasized the deleterious effect of the combination of Fe (III) ions with chloride ions at this low concentration. As shown in Table 3 increasing the chloride concentration to 0.1 M and 1 M produced only localized attack in the martensitic area at the welds.

Examination of the chloride content of the commercial γ and α-FeOOH samples (0.6 percent and 0.01 percent respectively) and calculation of the $FeCl_3$ content generated by the slurries indicated that the difference in chloride analysis might explain the observed phenomena. Analysis of the hydrogen peroxide used in the genesis of γ-FeOOH by corrosion of mild steel indicated a chloride ion content in the peroxide of 0.0005 percent. If all the chloride in the peroxide were incorporated into the corrosion products generated, sufficient chloride to cause cracking could have been introduced into capsules filled with slurries of these corrosion products.

As indicated in Table 3, chloride-free corrosion products consisting primarily of γ-FeOOH, obtained by corroding steel at room temperature in high purity water did not produce cracking when heated with water in capsules at 316 C; however, a slurry of this material with 0.0001 M $FeCl_3$ solution did produce cracks which penetrated the metal within 16 to 18 hours. Cracking was also produced by a slurry made from the commercial sample of α-FeOOH and the supernatant liquid filtered from a 4 percent slurry of commercial γ-FeOOH. This supernatant liquid was 0.001 M with respect to chloride ion and did not produce cracking in the absence of α- or γ-FeOOH.

Previous transformation studies[1] showed that aqueous slurries of

TABLE 3—Effect of Various Solutions and Slurries Containing Fe(III) and/or Chloride on Cracking at 316 C

Capsule Contents	Result of Treatment*
(1) 0.001 M. $FeCl_3$	Capsules cracked and leaked within 6 to 15 hours.
(2) 0.0001 M. $FeCl_3$	Very shallow cracks were produced within one week.
(3) 0.0005 M. $Fe_2(SO_4)_3$	No cracking observed within one week.
(4) 0.001 M. $Fe(NO_3)_3$	No cracking observed within one week.
(5) 0.003 M. NaCl	No cracking observed within one week.
(6) 0.01 M. NaCl	No cracking observed within one week.
(7) 0.1 M. NaCl	Slight attack at weld junction during one week.
(8) 1 M. NaCl	Localized corrosion in martensite penetrated welds within 20 hours.
(9) Aqueous slurry of γ-FeOOH containing 0.6% Cl^-	Capsules cracked and leaked within 6 hours.
(10) Aqueous slurry of γ-FeOOH generated by corrosion in H_2O_2 containing 0.0005% Cl^-	Capsules cracked and leaked within 12 hours.
(11) Aqueous slurry of γ-FeOOH generated by corrosion in high purity water	No cracking observed within one week.
(12) Slurry of γ-FeOOH in line 11 and 0.0001 M. $FeCl_3$	Capsules cracked and leaked within 16 to 18 hours.
(13) Aqueous slurry of α-FeOOH containing 0.01% Cl	Shallow cracks were produced within one week.
(14) Supernatant liquid γ-FeOOH slurry in line 9	No cracking observed within one week.
(15) Slurry of α-FeOOH in line 13 and liquid in line 14	Capsules cracked and leaked within 3 to 4 hours.
(16) Slurry of α-FeOOH containing 0.01% Cl^- and 0.003 M. NaCl	Moderately deep cracks were produced within one week.
(17) Slurry of γ-Fe_2O_3 containing 0.01% Cl^- and 0.003 M. NaCl	Moderately deep cracks were produced within one week.
(18) Slurry of α-Fe_2O_3 containing 0.02% Cl^- and 0.003 M. NaCl	Very deep cracks were produced within one week. One capsule cracked and leaked within 4 days.
(19) Slurry of Fe_3O_4 containing <0.01% Cl^- and 0.003 M. NaCl	No cracking observed within one week.

*At least 3 and usually more capsules were given each treatment.

TABLE 2—Chemical Analyses of Oxides and Hydrated Oxides

Material	Ferric Iron as Fe_2O_3	Ferrous Iron as Fe_3O_4	Water	Al as Al_2O_3	Mn as MnO	Si as SiO_2	Ca as CaO	Sn as SnO_2	Mg as MgO	Total Cations as Oxides	Cl^-	$SO^=_4$
γ-FeOOH	85.24	0.14	13.09	1.07	0.09	0.08	....	....	....	99.71	0.60	0.15
α-FeOOH	86.23	0.05	12.56	1.38	0.06	0.03	....	....	....	100.31	0.01	0.05
γ-Fe_2O_3	90.90	6.52	0.65	1.63	0.03	0.53	....	0.07	....	100.33	0.01	not determined
α-Fe_2O_3	97.51	0.20	0.50	1.86	0.05	0.06	....	....	....	100.18	0.02	not determined
Fe_3O_4	21.76	77.22	....	....	....	0.22	1.00	....	0.02	100.22	<0.01	not determined

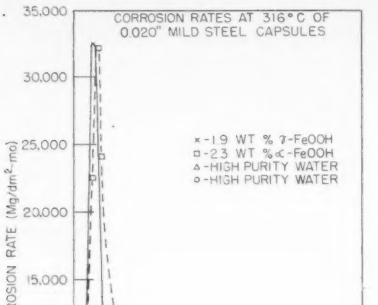


Figure 11—Typical corrosion rate curves obtained by the hydrogen effusion technique during heating of slurries of γ-FeOOH and α-FeOOH in steel capsules.

α-FeOOH and γ-FeOOH transform to α-Fe_2O_3 and Fe_3O_4 during heating in steel capsules at 316 C. The compound γ-Fe_2O_3, which may be an intermediate in the transformation of γ-FeOOH, also transforms to Fe_3O_4 and α-Fe_2O_3. Accordingly some experiments were undertaken to determine if slurries of γ-Fe_2O_3, α-Fe_2O_3 and Fe_3O_4 could also produce cracking in mild steel capsules during heating with chloride solutions.

Table 2 shows that the chloride content of the commercial supply of these materials is of the same order of magnitude as that of the α-FeOOH supply; for this reason analogous cracking tests were made on capsules containing slurries of α-FeOOH in chloride solution. The exact slurry compositions were not determined in this set of exploratory experiments, but were purposely made to be very concentrated with solid in order to determine whether or not the cracking could be produced under any circumstances. The slurries contained at least two or three times as much iron as did most of the γ-FeOOH slurries discussed earlier; (i.e., 5 to 10 weight percent of iron). Capsules heated at 316 C with aqueous slurries of these materials for four weeks did not leak, although superficial cracking like that shown in Figures 6 and 7 was produced by the chloride-bearing α-FeOOH, γ-Fe_2O_3 and α-Fe_2O_3 slurries. No cracking was observed in capsules heated with the Fe_3O_4 which contained less chloride than the other compounds. Lines 16 to 19 of Table 3 show that slurries of α-FeOOH, γ-Fe_2O_3 and α-Fe_2O_3 with 0.003 M NaCl produce more serious cracking than without the additional chloride. The fact that no cracking was observed in capsules heated with Fe_3O_4 in 0.003 M. NaCl suggests that Fe_3O_4 remains unattacked under these circumstances.

This investigation has shown that mild steel can undergo stress corrosion cracking at 316 C in $FeCl_3$ solutions. Chloride-bearing slurries of the ferric oxides and hydrated oxides, γ-FeOOH, α-FeOOH, γ-Fe_2O_3 and α-Fe_2O_3, or slurries of these compounds in contact with chloride-bearing solutions at this temperature can also produce this cracking.

These observations may be of practical significance in connection with boiler operations where substantial amounts of chloride may be present. During lay up periods when boilers are open to the atmosphere, corrosion is likely to occur at room temperature with generation of γ-FeOOH. With chloride present, this could give rise to corrosive attack, especially in stressed areas, if sufficient amounts of such material should be generated and not removed prior to the resumption of operation at elevated temperature. Any circumstances which result in the generation of ferric oxides in a boiler containing chloride ion could also result in analogous attack.

Acknowledgments

Thanks are due to G. N. Newport and W. A. Fraser for assistance during the course of this work, to D. H. Price for metallography of the specimens, and to the Analytical Chemistry Branch of the Metallurgy Division for analyses.

Reference

1. Mary Boehm Strauss and M. C. Bloom. *J. Electrochem Soc*, 107, No. 2, 77 (1960).
2. M. C. Bloom and M. Krulfeld. *J. Electrochem Soc*, 104, 264-269 (1957).

Any discussion of this article not published above will appear in June, 1961 issue.

Stress Corrosion Cracking of Carbon Steels In Concentrated Sodium Nitrate Solutions*

By R. L. McGLASSON, W. D. GREATHOUSE and C. M. HUDGINS

Abstract

A study is made of the operating and metallurgical variables which govern failure of steel in nitrate solutions. Laboratory tests using a notched C-ring stressed with a cadmium plated, mild steel bolt resulted in no failures for a variety of conditions. A similar specimen stressed in a stainless steel ring between bolts fixed with glass bead insulators produced failures. Some of the conditions for failure were determined using this latter test. When locally stressed above the yield point, carbon steels (N-80 and J-55) failed in hot (150 F-230 F) concentrated (43% and 29%) solutions of $NaNO_3$. Normalized N-80 failed at hardnesses of RC 20 and above. Quenched and tempered N-80 failed at hardnesses as low as RC 17 and AISI 1020 steel on a lower scale at RB 50. Failures were produced in solutions of pH 3 through 8.

Mixed concentrated solutions of sodium nitrate and calcium chloride, in which the $CaCl_2/NaNO_3$ ratio was 4, did not produce cracking in either normalized or quenched and tempered N-80 ranging in hardness from RC 15 through RC 36. Failures of RC 32 N-80 were not produced in this mixed solution from pH 3 through 8. Tests were made in solutions of pH 6 in which the $CaCl_2/NaNO_3$ ratio was varied from .003 through 4.0 on RC 35 N-80 material. Failures were produced through a ratio of 2.0. The critical ratio for failure is between 2.0 and 4.0 and was not more closely defined than this. Most of these tests were made on API tubing steels, but the results are considered applicable to a variety of low alloy AISI steels. 3.5.8

Introduction

SAFE COMPLETION of high pressure gas condensate wells requires that a fluid be left in the tubing-casing annulus that is of sufficient density to contain the pressure in the event of a pipe failure. The mud used for drilling the well is commonly used for this purpose. This mud, not being a solution, settles out and cakes over a period of time. This makes the tubing difficult to retrieve, thus hampering well workovers. Where more than one tubing string is used in completion, even greater difficulties result.

For this and other reasons, true dense salt solutions have been used as completion fluids. Two salts that are particularly attractive for this use are $NaNO_3$ and/or $CaCl_2$. They both have good solubility, high density, low cost. Both of these salts have been used for this purpose individually as well as in mixtures.

Completion fluid remains in contact with the outside of the tubing and the inside of the casing for long periods of time. Therefore, any corrosion and/or cracking effects of these solutions on the pipe must be clearly defined.

The corrosion effects of a number of such solutions have been discussed elsewhere.[1] But in this paper only the stress corrosion cracking effects of nitrate solutions will be considered.

The literature on cracking in nitrate solutions is extensive. Parkins[2] reviews this phenomenon in terms of theoretical mechanisms. In his paper the experimental data discussed relate to cracking in boiling calcium-ammonium nitrate solutions. Since NH_3 is also suspect as a crack promoter, one could not assume that similar results would occur for $NaNO_3$. In his own extensive work on this problem,[3] Dr. Parkins also used mixtures of calcium and ammonium nitrate. This work defines the important variables associated with cracking in this solution.

Mellor[4] lists two references to cracking in nitrate solutions. Cracking in cast iron vessels containing H_2SO_4-HNO_3 mixtures was cited. Intercrystalline cracking of mild steel plates in a solution of $(Ca\text{-}Na\text{-}NH_4)NO_3$ was reported. There are numerous other papers covering cracking of a variety of steels in nitrate solutions involving ammonia.

Schroeder[5] reported cracking of a high strength steel in dilute (0.01 N $NaNO_3$) solutions at 60 F. The material used was bridge cable wire of 180,000 psi yield strength which was stressed to 90,000 psi.

One investigator[6] reports that $NaNO_3$ was successfully used as a treatment to *prevent* cracking of seams in railroad boilers. Schroeder[5] tried using $NaNO_3$ as a cracking inhibitor for boiler plate in caustic solutions and reported that it did not work. The authors are given to understand, however, that $NaNO_3$ is commonly used as a boiler water treatment to prevent caustic embrittlement.

None of the cited literature gave very clear-cut data on the conditions for cracking in $NaNO_3$ without either ammonia or caustic embrittlement conditions being also present. Only one study involved $NaNO_3$ by itself—and this was on a much higher strength, higher carbon, less ductile steel than is found in oil country tubular goods. Also this test was in much more dilute solutions than are of interest here.

In no case had mixed concentrated $NaNO_3$-$CaCl_2$ solutions been evaluated for cracking. Thus there was no proof that oil country tubing steels would crack in either concentrated $NaNO_3$ or in the $NaNO_3$-$CaCl_2$ mixtures.

Laboratory tests were initiated to determine if cracking would occur in hot concentrated solutions of these salts. Before any results were available, however, plans for the study were expanded to define the conditions for cracking. This came about because of the occurrence of six coupling failures in a well containing $NaNO_3$ solution in the annulus. This report describes the field failures encountered.

Extensive laboratory tests were made. One large group of tests gave no failures under a variety of conditions. These results were invalidated when it was discovered that the cadmium-plated bolt being used to stress the specimen was preventing failures. This effect was discovered by the use of a different test jig. With this latter test jig, effects of steel hardness, solution pH, heat treatment, and $CaCl_2$ concentration on cracking in hot, concentrated $NaNO_3$ solutions were determined.

In-Service Failures

Well "A," the upper zone of a multiple well, was completed with 11 pounds per gallon of $NaNO_3$ solution above the packer. The tubing was EUE J-55 with

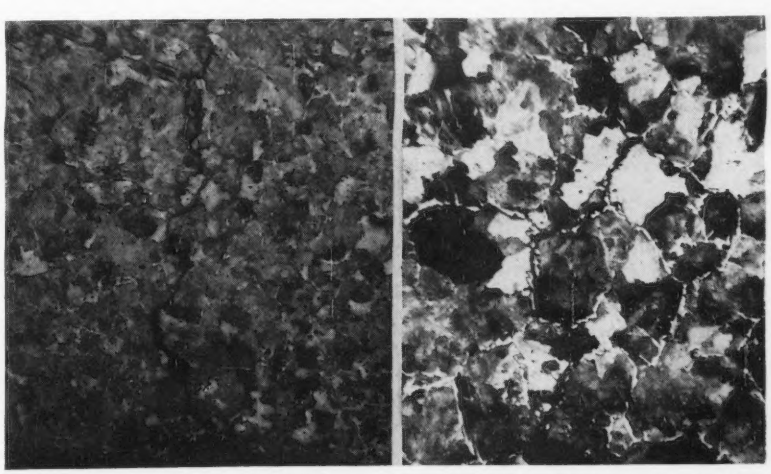


Figure 1—Photomicrographs of crack in J-55 tubing from well "A". Left: 60X, Picral etch; right: 150X, Picral etch.

* Submitted for publication January 19, 1960. A paper presented at the 16th Annual Conference, National Association of Corrosion Engineers, Dallas, Texas, March 14-18, 1960.

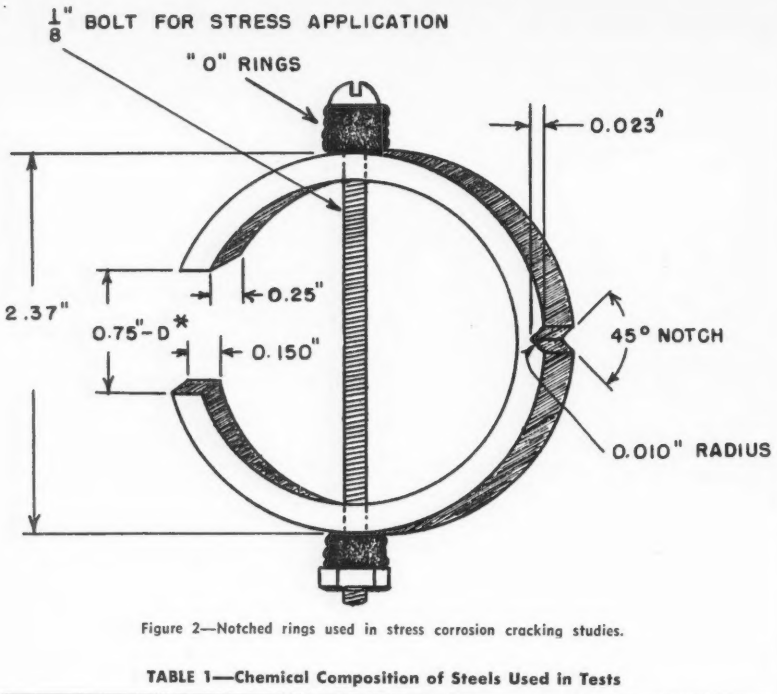


Figure 2—Notched rings used in stress corrosion cracking studies.

TABLE 1—Chemical Composition of Steels Used in Tests

Steel	COMPOSITION (Weight Percent)					Comparable AISI Alloy
	Carbon	Manganese	Phosphorus	Sulfur	Other	
*N-80	0.46	1.5	0.020	0.036	0.20 Mo	4042
*J-55	0.44	0.7	0.022	0.025	.....	1039
**1020	0.20	0.5	0.04	0.05	.....	1020

*API Standard 5A Steels. (A Performance Standard, not a compositional designation.)
**Typical composition—not analyzed.

8RD slim hole couplings. Tubing was set at 9,534 feet. The SITP was 1,750 psig. BHT was approximately 180 F. Within a few days the tubing pressure dropped, and the tubing was pulled. Five couplings (at 6,984 feet, 8,769 feet, 9,134 feet, 9,422 feet and 9,464 feet) were split open. A thorough metallographic examination of these failures showed no evidence of manufacturing seam defects. The failure paths and numerous shallower cracks were brittle in appearance and primarily intergranular. Figure 1 shows photomicrographs typical of those found in these couplings and later on in tubing in this well.

When recompleted, the $NaNO_3$ was displaced from this well using 11 pounds per gallon of $CaCl_2$ solution. Because of incomplete displacement, severe corrosion caused by the remaining $NaNO_3$-$CaCl_2$ mixture[1] once again caused the tubing to be pulled approximately 18 months later. Aside from the severe external corrosion in restricted regions of the string, 32 couplings were found to contain longitudinal cracks using an electromagnetic inspection system. Deep cracks also were found in the body of two tubing joints, neither of which cracks were in regions of severe corrosion.

Well "B," the upper zone of a dual well, was completed with concentrated $NaNO_3$ solution. This well was 8,760 feet with a BHT of approximately 180 F. The 292 joints of J-55 EUE tubing and 8RD slim hole couplings were inspected for cracking using the same techniques used for well "A." No cracking of either couplings or tubing was found.

There is no further field data which would explain the difference in results in these two wells. Laboratory data reported subsequently show cracking occurs under a wide variety of steel and solution conditions. On the other hand, laboratory data also show that this nitrate cracking phenomena is very sensitive to small bimetallic hookup influences. It is felt that the lack of cracking in well "B" was due to some such unknown influence.

Laboratory Test Procedures

Test Specimens

Three types of stress cracking testing jigs were used in the laboratory studies.

Figure 2 shows the notched C-ring type specimen used in most of these tests. Here the device is shown with the deformation being applied by a bolt. For the tests herein described, this bolt was a cadmium plated, ⅛-inch mild steel bolt; the washers were stainless steel. This type test arrangement was designed for sulfide cracking studies, and its use is described in an earlier paper.[8]

Figure 3 shows this same notched ring specimen being deformed between two screws in a stainless steel ring jig. The notched ring is electrically isolated from the jig by glass beads. This arrangement was found to be the most suitable for these nitrate cracking studies.

This notched ring is deformed, measured amounts with measurements of 0.010 inch accuracy being made between the ends of the opening in the "C." The relation between this deformation and the deformation for onset of macroscale yielding is determined by use of a Phillips' C-ring[9] and its load-deformation curve as shown in Figure 4. In other words, a Phillips' C-ring of the material to be tested is loaded in compression and the load-deformation curve obtained. The point of linearity departure on this curve is designated the yield point and the deformation at that point the "yield deformation." The ¼-inch cracking ring from this same material can then be deformed to incremental portions of this "yield deformation" using, of course, a correction factor for the difference in measurement positions.

For a few tests (those on coupling materials which failed in service), the available material could not be fabricated into notched rings and consequently 1/16 inch by 3/16 inch by 4½ inch longitudinal beam specimens were used. The jig used for these tests is shown in Figure 5.

R. L. McGLASSON is a metallurgist in the Materials Section of Production Research of Continental Oil Company. His work deals with corrosion metallurgy. He has a BS in physics and mathematics from Northwestern State College (Okla.). Formerly he was employed by Boeing Airplane Company.

W. D. GREATHOUSE is supervisor of the Materials Section, Production Research Division, Continental Oil Co., Ponca City, Okla. He is co-author of several papers on petroleum production corrosion problems, has a BS in chemical engineering from Texas Technological College and a member of NACE and AIME.

C. M. HUDGINS is a research chemist in the Materials Section of the Production Research Division, Continental Oil Co. Ponca City, Okla. He is concerned with corrosion and special physical chemistry problems encountered in production of oil. He has a BS and MS from Texas A&M College and a PhD from Louisiana State University.

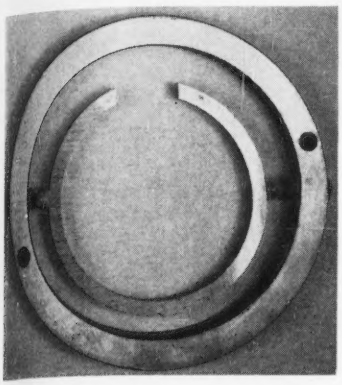


Figure 3—Notched C-ring stressed between two screws in stainless steel ring. Specimen is electrically isolated from jig by glass beads.

Test Materials

Most of these tests were made on the API tubing materials (i.e., N-80 and J-55). These tubing names actually are mechanical property designations (80,000 psi. and 55,000 psi. minimum yield strengths, respectively). In these tests, however, the specimens were heat treated to a variety of different strengths; consequently these designations lost their real meaning for this work and refer only to their chemical compositions which are shown in Table 1. The AISI alloy most nearly comparable to these compositions is also shown. Since one significant data point was obtained on an AISI 1020 steel coupon, a typical composition for this material is also given. This 1020 steel was a rimmed steel whereas the tubing steels used were killed steels.

Test Solutions

Several different solutions were used in testing (see Table 2). All of these solutions were quite concentrated as can be seen, and correspondingly dense. Salts used in these tests were commercial grade salts being used for the annular fluids. The composition of test solutions extracted from the mixtures designated "solution 5" and "solution 6" are not exactly known but definitely did not contain all of the material listed. When the dissolution of these concentrations of $NaNO_3$ and $CaCl_2$ is attempted, the much lower solubility of NaCl causes it to drop out of solution by common ion effect. For test purposes and correspondingly where such densities are needed for a packer fluid, only the supernatant liquids—the true solution portions—of these mixtures were used.

TABLE 2—Composition of Test Solutions Used

Test Solution	Composition	WEIGHT Percent of $NaNO_3$	WEIGHT Percent of $CaCl_2$
Solution No. 1	507 gm $NaNO_3$; 672 ml H_2O	43	0
Solution No. 2	1,000 gm $NaNO_3$; 2,500 ml H_2O	29	0
Solution No. 3	2,792 gm $CaCl_2$; 3,785 ml H_2O	0	42
Solution No. 4	2,028 gm $NaNO_3$; 9 gm NaOH and 2,688 ml H_2O	43	0
*Solution No. 5	700 gm $NaNO_3$; 1,000 gm $CaCl_2$ and 2,000 ml H_2O	19	27
*Solution No. 6	880 gm $NaNO_3$; 3,600 gm $CaCl_2$ and 4,000 ml H_2O	12	48
Solution No. 7	800 gm $NaNO_3$; 2,000 ml H_2O	29	0
Solution No. 8	800 gm $CaCl_2$; 2,000 ml H_2O	0	29

*As mixed these solutions precipitate NaCl. The decanted liquids were used in these tests.

Tests With Bolt-Stressed Ring

The tests made in this manner produced largely negative results. A summary of the significant variables tested will be presented rather than individual test details.

Eleven different test conditions involving 44 different bolt-stressed specimens were conducted. All materials listed in Table 1 were tested in solutions 1 through 5 of Table 2. The N-80 tests were oil quenched and tempered to hardnesses of RC 40 through RC 30 with specimens at each integer hardness. J-55 tests were made on normalized and tempered specimens ranging in hardness from RB 84 through RB 91. Other bolt stressed tests were made using U-bent 1020 steel coupons both in the cold-rolled condition and after spheroidizing at 1,200 F for 8 hours. Tests were made at different temperatures from 150 F to boiling (230 F).

These tests include applied deformations ranging from 10 percent of yield to 130 percent of yield. None of the tests were stopped in less than a month, most were continued longer than two months, and one was extended to seven months.

In all of these tests, only one ring failed. This was an RC 37, N-80 ring which failed within 5 days in solution No. 1 deformed to 60 percent of yield deformation. Since several other rings of similar properties and both similar and higher stresses did not fail, this failure is considered anomalous for this type of test. (The bolt probably was not in actual contact with the ring on this one specimen.)

A number of test variables were tried in order to induce failures similar to those found in the coupling failures. Solution No. 4, a very alkaline solution, was tried to see if caustic cracking might be involved. It was thought that this phenomenon might have resulted from alkaline muds adhering to the coupling during nitrate displacement and then subsequently

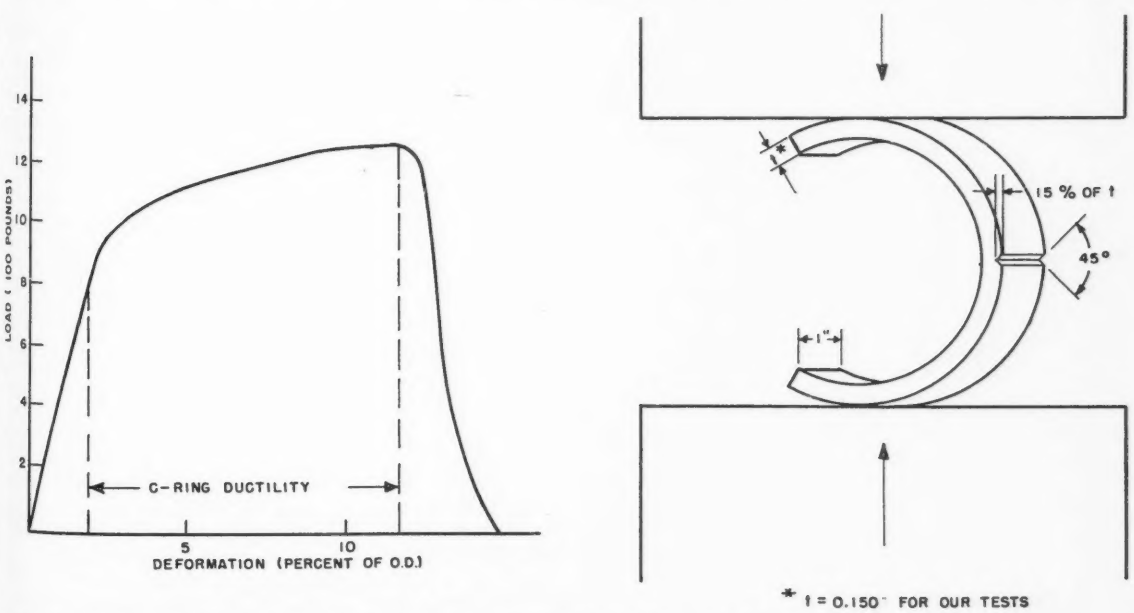


Figure 4—Modified Phillips' C-ring and typical C-ring ductility curve. This type of test has been found to be a good measure of tubing notch sensitivity.

559t

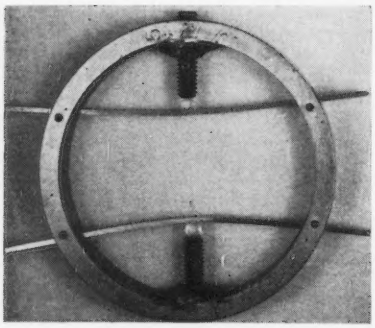


Figure 5—Beam specimen jig used for longitudinal beam tests on coupling materials.

TABLE 3—Results of Tests in Nitrate Solutions of Hardness Variations Using N-80 or 1020 Heat Treated to Produce Spheroidal Carbide Distributions.*

Tempering Temperature, °F.**	Hardness (RC)	Failure Time
1,000	36	7 Days
1,050	35	1½ Days
1,100	30	1½ Days
1,150	28	2 Days
1,200	27	34 Days
1,200	26	1½ Days
1,200	23	1½ Days
1,300	21	34 Days
1,250	19	2 Days
1,400	17	2 Days
AISI 1020 as Rolled	.....	Less than 30 Days
AISI 1020 Spherodized at 1,200	RB 50	Less than 30 Days

*All specimens deformed 130 percent of yield deformation except 1020 steel coupon. Failure times are not exact but indicate time within which specimen failed.

**All N-80 specimens were oil quenched from 1,600 F, then tempered at these temperatures. Hardness discrepancies for tempering temperatures due to furnace changes.

TABLE 4—Results of Tests in Nitrate Solutions of Hardness Variations Using N-80 Normalized or Normalized and Tempered to Produce Pearlitic and/or Bainitic Carbide Distributions.*

Tempering Temperature, °F**	Hardness (RC)	Failure Time
Normalized Only	24	2 Days
Tempered at 200	25	34 Days
800	24	2½ Days
1,200	21	15 Days
1,100	21	***NF 44 Days
1,000	20	***NF 47 Days
1,300	17	***NF 44 Days
1,300	15	***NF 47 Days

*The steels in these tests are in conditions comparable to "as received" N-80 tubing. Failure times not exact but indicate failure occurred within listed time.

**All specimens normalized from 1,600 F, then tempered at these temperatures. Hardness discrepancies for tempering temperatures due to furnace changes.

***No failure.

becoming saturated with nitrate solution. This solution did not result in any failures.

It has been suggested[10] that environments which cause cracking tend to do so when precipitation of the solute occurs on the metal surface thus creating severe concentration cell gradients. To test this as a possible source of the cause of cracking, solutions were boiled down in two tests so that the upper rings were out of the liquid.

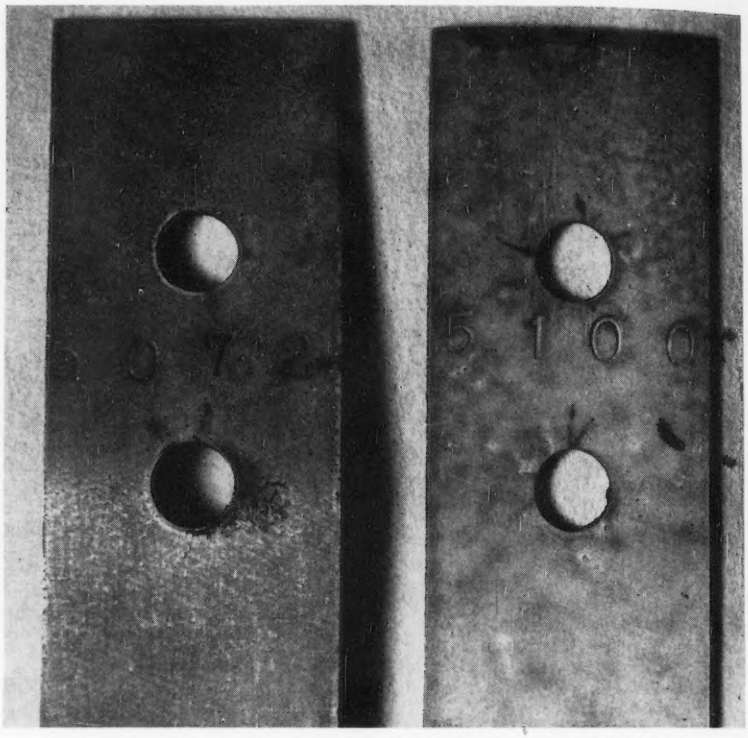


Figure 6—Photograph of cracks around drilled hole in 1020 steel coupon of RB 50 hardness.

Severe salt deposition occurred on these rings but no failures were noted.

When this failure to get cracking is compared with the ease with which cracking is obtained in identical systems (see next section) using an electrically isolated test specimen, one is forced to conclude that the cadmium plated bolt was preventing failures from occurring. This indicates that this phenomenon is not only electrochemical in nature but that it is quite sensitive to prevention by extraneous effects of mild bimetallism.

Tests With Electrically Isolated Ring Specimen

Preliminary Test

At this stage the problem of either finding another cause of the field cracking failures or producing them in the laboratory was becoming serious. It was decided to further refine the test by eliminating the bolt and using the stainless steel ring jig shown in Figure 3. Only one ring of N-80 was used in this trial test. It was an oil quenched and tempered ring of RC 35 hardness. The ring was immersed in solution No. 1 of Table 2 and kept at a temperature of 150 F. The pH of this solution was approximately 6. Failure occurred within 12 hours.

Effect of Hardness

Once a test result was obtained that agreed with the field results, tests were initiated to evaluate specimen and solution variables. The first tests involved hardness as a variable. N-80 specimens were oil quenched and tempered to a number of different hardnesses and immersed in solution No. 2 at temperatures that varied from 150F to 203 F. The results of this test are shown in Table 3.

Cracking was also produced around a drilled hole of a 1020 steel coupon being exposed to a similar nitrate solution. Figure 6 is a picture of this cracking, and this is listed as a failure in Table 3.

The coupon cracking and the oil quenched and tempered N-80 test data are listed together because both are steels with spheroidal carbide distributions. From these data it would appear that carbon steels which are heat treated in a manner to produce spheroidal carbides are susceptible to cracking in $NaNO_3$ solutions at almost all practical hardness levels.

Effect of Normalizing Heat Treatment

In his studies of nitrate cracking,[2,3] Dr. Parkins points out that the spheroidal carbide distribution is the most susceptible condition for cracking of steels. Certainly the tests reported above confirm that susceptibility to cracking exists for such steels in $NaNO_3$ solutions. Tests were also run to determine the hardness range of susceptibility for normalized steels with pearlitic and/or bainitic carbide distributions. The tests were made on N-80 steel normalized or normalized and tempered to different hardnesses. The specimens were deformed to 130 percent yield deformation and immersed in solution No. 2 at 150 F to 203 F temperature. The results are given in Table 4.

These results definitely indicate that there is a lower hardness limit of about RC 20 for cracking of normalized carbon

TABLE 5—Results of Tests of N-80 in a Mixture of $CaCl_2$-$NaNO_3$ with a $CaCl_2/NaNO_3$ Weight Ratio of 4. Specimens were stressed to 130 per cent yield deformation.

Heat Treatment, °F.		Hardness (RC)	Failure Time
N 1600	T 200	25	NF* for 47 Days
N 1600	T 1000	20	NF* for 47 Days
N 1600	T 1300	15	NF* for 47 Days
OQ 1525	T 1300	21	NF* for 47 Days
OQ 1525	T 1200	27	NF* for 47 Days
OQ 1525	T 1000	36	NF* for 47 Days
OQ 1600	T 900	35	NF* for 60 Days
OQ 1600	T 1050	32	NF* for 60 Days
OQ 1600	T 1100	30	NF* for 60 Days
OQ 1600	T 1100	27	NF* for 60 Days
OQ 1600	T 1150	26	NF* for 60 Days
OQ 1600	T 1300	20	NF* for 60 Days

*No failure.

TABLE 6—Results of Tests of Oil Quenched and Tempered N-80 Specimens in Mixed $NaNO_3$-$CaCl_2$ Solutions with Different $CaCl_2/NaNO_3$ Weight Ratios

Hardness (RC)	$CaCl_2/NaNO_3$ Weight Ratios	Failure Time
37	0.003	7 Hours
36	0.008	23 Hours
34	0.013	23 Hours
35	0.07	52 Hours
33	0.16	30 Hours
34	0.4	47 Hours
36	0.8	30 Hours
32	2.0	56 Hours
36	4.0	NF* for 60 Days

*No failure.

steels. This would be substantially better than for the spheroidal treatments which showed no apparent minimum.

Effects of pH on $NaNO_3$ Cracking

The above-described tests were made in "as mixed" solutions which normally were of about pH 6. N-80 specimens oil quenched and tempered to approximately RC 35 hardness were deformed to 130 percent yield deformation and exposed to solution No. 2 at 176F with different pH's ranging from 2 through 8. The pH adjustments were made with HNO_3 or NaOH. Tests were made at each integer pH within the range. All specimens failed within 5 hours.

Effects of CaCl, Additions on $NaNO_3$ Cracking

It was found that higher densities could be obtained using $NaNO_3$-$CaCl_2$ mixtures than could be obtained with either solution alone. Solutions No. 5 and No. 6 were used in the initial tests. Solution No. 6 at 158F to 207F was used to test N-80 specimens of different hardnesses. This solution has a $CaCl_2/NaNO_3$ weight ratio of 4. The specimens were stressed at 130 percent yield deformation. The results are shown in Table 5. It can be seen that no failures occurred in this solution with steels that readily failed in straight nitrate solutions.

The above test was made in solution 6 at approximately pH 5. A test was then made using the same solutions but with pH's ranging from 3 through 8 at each integer pH in the range. Quenched and tempered N-80 of RC 32 hardness was used. The solutions were at 176F. No failures occurred at any of the pH's tested.

From these tests it was thought that the $CaCl_2$ might serve as a cracking inhibitor at much lower concentrations. Solutions No. 7 and No. 8 were mixed in various proportions to provide a wide range of $CaCl_2/NaNO_3$ weight ratios. Quenched and tempered N-80 specimens of approximately RC 35 hardness were tested in these solutions at 185F. The results are shown in Table 6. These tests clearly showed that the $CaCl_2/NaNO_3$ weight ratio must be in excess of 2 if cracking is to be avoided. This means the dividing line is some place between a ratio of 2 and 4. No further definition was attempted.

Tests With Beam Specimen

An attempt was made to reproduce the coupling failures that had occurred in J-55 couplings of well "A." By the time metallographic examinations were completed, it was impossible to obtain a satisfactory C-ring from the remaining sample material; consequently longitudinal beam specimens were used in these tests. The specimens were made of as received material from two couplings—one RC 24 and one RC 16. The specimens were either cold worked by reverse bending or by notching with a chisel before being bent in the stress jig. The applied deformation in the jig was substantially greater than yield deformation. The tests were conducted in solution No. 1 at 185F and in solution No. 5 at boiling conditions. None of these specimens failed in 4 months' exposure.

These couplings had failed in service under the severe stress conditions associated with made up API 8RD slim hole couplings. These failures were from transverse stresses. Failures in similar materials loaded in the transverse direction using C-rings were produced in laboratory tests. The stress conditions on these beams were more severe than would exist for either the made up couplings in the field or the laboratory C-ring tests. From these data the authors are forced to conclude that the nitrate cracking susceptibility of seamless tube steels is much higher in the transverse than in the longitudinal direction.

Conclusions

1. API J-55 tubing and couplings will fail by stress-corrosion cracking in concentrated $NaNO_3$ packer fluids. The highly stressed couplings are particularly susceptible.

2. Cracking in $NaNO_3$ is very sensitive to electrochemical variables as evidenced by the lack of cracking in well "B" and the failure to obtain cracking of specimens stressed with a cadmium-plated, mild steel bolt.

3. Cracking in $NaNO_3$ is an electrochemical phenomenon and does not require salt crystal deposits.

4. Stress cracking of carbon steels occurs in hot, concentrated $NaNO_3$ solutions; this can be produced in the laboratory with the notched ring test if it is electrically isolated from extraneous effects of bimetallism.

5. Carbon steels heat treated to produce spheriodal carbide distributions using either oil quenching and tempering or spheroidizing treatments will crack in hot, concentrated $NaNO_3$ solutions through all significant hardnesses (RC 40 to RB 50) under the stress conditions herein described.

6. Carbon steels heat treated to produce pearlitic and/or bainitic carbide distributions using normalizing and tempering treatments crack in hot, concentrated $NaNo_3$ solutions at hardness above RC 20 but are apparently not susceptible below this hardness under the stress conditions herein described.

7. Cracking occurred in hot, concentrated $NaNO_3$ solutions at all pH's from 2 through 8.

8. Cracking did not occur in hot, concentrated mixed solutions of $NaNO_3$ and $CaCl_2$ using specimens ranging in hardness from RC 20 through RC 36 at pH's from 2 through 8 when the $CaCl_2/NaNO_3$ weight ratio was 4.

9. Cracking occurs in hot, concentrated mixed solutions of $NaNO_3$ and $CaCl_2$ with $CaCl_2/NaNO_3$ weight ratios as high as 2.

10. The susceptibility of carbon steel seamless tubes to cracking in $NaNO_3$ is much greater when stressed in the transverse direction than when stressed longitudinally.

Acknowledgments

The authors wish to express their thanks to W. M. Rosborough and J. L. Schiltz for their skilled efforts in conducting most of the laboratory work reported here. They also thank Continental Oil Company, at whose expense this work was accomplished, for permission to publish this work.

References

1. C. M. Hudgins, J. E. Landers and W. D. Greathouse. Corrosion Problems in the Use of Dense Salt Solutions as Packer Fluids. *Corrosion*, 16, 535t (1960) Nov.
2. R. N. Parkins. Stress Corrosion Cracking of Mild Steels. Chapter 10 of "Stress Corrosion Cracking and Embrittlement," a book edited by W. D. Robertson, John Wiley & Sons, 1956, pp. 140-157.
3. R. W. Parkins. The Stress Corrosion Cracking of Mild Steels in Nitrate Solutions. *Journ. of Iron and Steel Inst.*, 172, 149-161 (1952) October.
4. Mellor. A Treatise on Inorganic Chemistry. Longmans, Green & Co. (1934), Vol. XIII, p. 346.
5. W. C. Schroeder. Proceedings of the American Society for Testing Materials, Vol. 36, Part II, 721 (1936). (Book).
6. A. A. Berk. *Ind. Eng. Chem.*, 40, No. 8, 1371 (1948).
7. W. C. Schroeder. Intercrystalline Cracking of Boiler Steel and Its Prevention. Bur. of Mines Publication No. 443 (1941).
8. McGlasson and Greathouse. Stress Corrosion Cracking of Oil Country Tubular Goods. *Corrosion*, 15, No. 8, 55-60 (1959) August.
9. F. A. Prange. Mechanical Properties and Corrosion Resistance of Oil Well Tubing. *Corrosion*, 15, No. 2, 13-18 (1959) February.

10, Gulbransen and Copan. "Effect of Stress and Environment on the Microtopology of the Corrosion Product." Physical Metallurgy of Stress Corrosion Fracture, Interscience Publishers, (1959).

DISCUSSION

Question by Parke D. Muir, Dowell, Inc., Tulsa, Oklahoma:

You mentioned that at a $CaCl_2$:$NaNO_3$ ratio of 4:1, you did not get cracking while at a ratio of $CaCl_2$:$NaNO_3$ of 2:1 and lower, you got cracking. Did you receive pitting on those solutions containing a ratio of 4:1 of $CaCl_2$:$NaNO_3$.

Reply by R. L. McGlasson:

Yes, 1/16" coupons were penetrated in 40 days in such solutions.

Question by John H. Naschke, Houston, Texas:

Are you inhibiting those brines you find to have corrosion rates considered tolerable such as the sodium and calcium chlorides?

Reply by R. L. McGlasson:

Yes, we add inhibitors as an extra precaution. But we would not depend on inhibitors to control corrosion by solutions known to be excessively corrosive.

Question by L. W. Vollmer, Pittsburgh, Pa.:

Will inhibitors stop cracking of steel in nitrate solutions?

Reply by R. L. McGlasson:

We did not investigate effects of inhibitor on nitrate cracking.

Question by Charles E. Fox, Dowell Div. of Dow Chemical Co., Tulsa, Okla.:

Was any demarcation noticed between pitting and cracking. How much overlap? Was any correlation worked out or noticed between the two forms of corrosion?

Reply by R. L. McGlasson:

The phenomena are definitely overlapped. At the 2:1 $CaCl_2$-to-$NaNO_3$ ratio at which cracking definitely occurred, a pitting attack occurred on coupons at a rate of greater than 500 MPY.

Any discussion of this article not published above will appear in June, 1961 issue.

Technical Papers on Corrosion Welcomed

Authors of technical papers on corrosion are invited to submit them for review without invitation to the Editor of Corrosion. Write for "Guide for the Preparation and Presentation of Papers" sent free on request to prospective authors.

NATIONAL ASSOCIATION of CORROSION ENGINEERS

Practices and Experience With Protective Jackets For Outside Plant Lead and Aluminum Sheathed Cable

A Report Prepared Jointly by NACE Task Group T-4B-5* On Non-Metallic Sheaths and Coatings,[1] and by The AIEE Sheaths and Coverings Subcommittee[2]

NACE TECHNICAL COMMITTEE REPORT

Publication 60—14

Introduction

INFORMATION ON electric utility practices and experience with jacketed metallic-sheathed power cables was obtained in 1957 by sending a questionnaire to 35 utilities in the United States and Canada. This project was carried out jointly by the NACE Non-Metallic Sheaths and Coatings Task Group T-4B-5) and the AIEE Sheaths and Coverings Subcommittee. The survey is similar to an earlier one, a summary of which was published in the March 1950 issue of *Electrical Engineering*.

The data received on lead-sheathed cable are summarized and included in detail in the tables. Only three utilities provided data on aluminum sheathed cables; their answers are included without summarization.

Although the list of utilities surveyed in 1957 differs somewhat from that of the survey published in 1950, comparisons which appear pertinent are made with data used in the earlier report.

In tabulating the answers, a few minor

Abstract

Questionnaire replies received from 32 electric utility companies are tabulated and evaluated regarding practices and experiences with protective jackets for outside plant lead and aluminum sheathed cable. Extensive information is given on the following subjects: reasons for use of jacketed lead sheath cable in ducts, types and thicknesses of jackets used, value of jacket on lead sheath in reducing mechanical damage due to cable movement, type of coverings used on cables in manholes, installation and removal of duct lay jacketed cables, lubricants for lead sheath cables in ducts, use of buried jacketed cables, thicknesses of jackets, covering of buried cable joints. Data are reported on use of jacketed lead sheathed cables—duct-lay and buried. Reports from three utility companies are summarized regarding the use of jacketed aluminum sheathed cable. 7.7

* Now known as T-4C.
[1] L. O. McCormick, chairman.
[2] John J. Rueckert, chairman.

TABLE 1—Extent of and Reasons for the Use of Jacketed Lead Sheath Cable In Ducts

Company	Question 1**	Question 2** a	b	c	d	e	f	g	h	Question 3** a	b	c	Question 4** 4 to 5	7 to 8	11 to 15	17	22 to 28	33 to 38	40 to 46	66 to 69	115 to 138	Question 5**	Question 6** a	b
A	Yes	3	1	2							X		X		X			X				1%	Increasing	Increasing
B	Yes	1	2								X				X		X			X	X	40%	50%	60%
C	Yes		X	X				X		X					X							100%	100%	100%
D	Yes	3	1	2							X		X		X			X				10%	10%	10%
E	Yes		2	1							X							X				<1%	<1%	<1%
F	Yes	X		X							X		X		X			X		X	X	8%	10%	12%
G	Yes		1	2							X		X		X		X		X	X	X	2%	10%	30%
H	Yes	1	2	3							X		X	X			X					10%	15%	20%
I	Yes		1	2						X					X							75%	Increasing	
J	Yes	3	2	1							X		X				X		X			20% (1)	Increasing (2)	Increasing (2)
K	Yes	2	1	3							X		X		X		X					3.2%	5%	5%
L	Yes	2	1				3			X			X		X			X				100%	100%	100%
M	Yes	X	X	X							X		←				X				→	100% (3)	Increasing	Increasing
N	No										X											(4)		
O	Yes	3	2	4			1			X			X		X		X	X				100%	(5)	(5)
P	Yes		1	2							X				X							<1%	<1%	<1%
Q	Yes	2	1								X				X		X				X	50%	75%	75%
R	Yes	2	1	3							X						X					20%	30%	40%
S	Yes	X	X	X							X						X					30%	30%	30%
T	No										X											0%		
U	Yes	3	1	2						X			X		X		X					90% +	90% +	90% +
V	Yes	1	3	2				4		X			X		X			X		X		75%	75%	75%
W	Yes	1	2								X		X		X			X		X		23%	25%	25%
X	No										X											0%	0%	0%
Y	Yes		X								X		X		X		X				X	5%	1%	2%
Z	Yes	1	2								X								X		X	100% (3)		
AA	Yes		1	2							X				X			X				<1%	<1%	<1%
BB	Yes	2	1							X			X		X	X						2%	Increasing	Increasing
CC	No																							
DD	No																							
EE	Yes		X	X					(7)		X		X		X			X				2%	2%	2%
FF	Yes	3	1		4			2		X			X		X		X	X				100%	100%	100%

**Questions 1—6 are found on Page 121.

(1) This represents average purchases for the last five years for both duct lay and buried applications.
(2) Depends upon how much plain lead sheath cable is returned to stock.
(3) Transmission only.
(4) Recently purchased 8000 ft of 1/0 1/C 15 KV with poly jacket for underground residential system part in transite duct and part direct burial.
(5) Depends upon experience with present installations.
(6) If the cost of jackets were reduced significantly our usage would probably increase to 100 percent.
(7) Hydrostatic oil pressure on dips.

modifications were made in the data received to improve consistency of the answers when other data in the reply indicated the correctness of the modification. These changes were held to a minimum. In other instances some inconsistencies are evident, but sufficient information was not available to allow changes to be made without the possibility of reporting results incorrectly.

Jacketed Lead-Sheathed Duct Lay Cable

Extent of and Reasons for Use[3]

The use of jacketed cables is widespread. Twenty-seven of the reporting utilities use such cables in duct at voltages from 4 to 138 kv. The percentage of utilities reporting the use of jacketed cable is the same as in the 1950 report.

The reasons for using jackets are listed in Table 2 below with an indication of the relative importance the industry gave to each reason.

[3] See Table 1 for details.

TABLE 2

Reason	Relative Importance[4]
Protection against sheath damage from local galvanic cell action	64
Protection against sheath damage from stray current electrolysis	37
Protection against sheath damage from chemical action	36
Protection against damage during installation	5
Protection against sheath damage from remote faults	4
Protection against hydrostatic oil pressure on dips	2
Protection against excessive wear of cable sheath at duct edge and supports	1

[4] The following illustrates how the replies were weighted to obtain an indication of relative importance:

Order of Importance	Value
1	3
2	2
all reasons of equal importance	2
3	1
4	1

TABLE 3

Number of Utilities	Percentage of Lead-Sheathed Cable Now Bought Which Is Jacketed
4	100
2	100 (Transmission only)
1	90 - 99
0	80 - 89
2	70 - 79
0	60 - 69
1	50 - 59
1	40 - 49
1	30 - 39
3	20 - 29
2	10 - 19
7	1 - 9
3	More than 0 but less than 1

As in the 1950 report the important difficulties which prompted the use of jackets are the various types of corrosion damage to the lead sheath. There does appear to be increased emphasis on the need for protection specifically against local galvanic cell action. Other advantages which jackets may have do not appear to be a major factor in determining whether or not a jacket is used.

In the earlier survey, 12.5 percent of the reporting utilities expressed the belief that jackets are justified for general use throughout their systems. The present survey shows that 8 utilities, or about 25 percent of those reporting, believe the use of jackets as protection is justified throughout their systems. The findings reported in Table 3 indicates their views are generally put into practice. Most utilities which buy jacketed cables, however, specify them for substantially less than 50 percent of their cable requirements, and more than a third specify jackets for less than 10 percent of their cable purchases.

In regard to future increases in the percentage of jacketed cable used, four utilities are already buying jacketed cable only. Eight others reported no contemplated increases in the percentage used over the next 10 years. Fourteen utilities indicated that their relative usage of jacketed cable would increase over the next 10 years.

Types and Thicknesses of Jackets; Thicknesses of Lead Sheath Under Jackets[5]

Of the 27 utilities using jacketed lead-sheathed cables in ducts, 20 currently use a reinforced neoprene jacket exclusively. Table 5 gives a listing of the types of jackets and the number of utilities presently using them:

Aside from the elimination of extruded neoprene and duck tape and asphalt, data on types of jackets currently installed is similar to the practices reported in 1950.

It is gratifying to observe that industry standards for thicknesses of reinforced neoprene jackets are followed by 22 utilities whereas only four indicate use of other specifications. For other types of jacketed cables, 10 of 14 utilities require that jacket thicknesses be generally proportional to the cable diameters.

Twelve utilities which use plain or copper bearing lead sheaths report that they do not make a reduction in the lead thickness for jacketed cables. Another

[5] See Table 4 for details.

TABLE 4—Types and Thicknesses of Jackets; Thicknesses of Lead Sheath Under Jackets—Duct Lay Installations

Company	Question 7 a	b	c	d	e	Question 8	Question 9	Question 10 a	b	Question 11 a	b
A	X					Yes		Yes		15%	
B	X					Yes		No	Yes	0%	33%
C	X					Yes	Yes	No	No		
D	X	X				Yes	Yes	No	No		
E	X					Yes		No			
F	X					Yes		Yes	Yes	15%	15%
G	X					Yes		No	No		
H	X					Yes		Yes	Yes	15%	
I	X					Yes			Yes		20%
J	X					No		Yes		7 to 13%	
K	X					Yes	Yes		Yes		20%
L	X					No	Yes	No			
M					(8)		No	No	No		
N						Yes	Yes	No	No		
O	X				(9)	Yes	No	Yes	Yes	(10)	(10)
P	X					(11)	(11)	Yes		10% ±	
Q	X					Yes		Yes		15%	
R	X	X				Yes	Yes	Yes		15%	
S	X	X				No	No	No			
T											
U	X					Yes			Yes		20 to 25%
V	X					Yes		No	No		
W	X					Yes		Yes		15%	
X											
Y	X	X				Yes	Yes	Yes	Yes	15%	15 & 33%
Z		X			(12)		No	No			
AA	X					No		Yes	Yes	15%	15%
BB	X					Yes		Yes	Yes	20% ±	20% ±
CC											
DD											
EE	X		X			Yes	(11)	No	No		
FF	X					Yes	Yes		Yes		10%

(8) Rubber-bitumen sandwich now most used, sometimes with a Mylar layer. Covered with neoprene-faced friction tape for duct use. Occasional use made of PVC-tape on replacement cables when duct clearance is too small for thicker wrap.
(9) PVC tape field applied on leaded stock cable. We apply one layer with ½ lap of 20 mil. PVC tape.
(10) For Core Thickness 0-969; 970-1187; 1188-1405; 1405-1623 mil. Lead thickness for jacketed cables is 75; 80; 85; 90; mil. etc. respectively.
(11) Recommendations from manufacturers usually followed.
(12) Alternative layers of self-vulcanizing rubber and impregnated cotton tapes, with bitumen compound between layers; hessian tapes overall.

TABLE 5

Material	Present Survey	1950 Report Data
Reinforced neoprene	25	24
Extruded neoprene	0	9
Extruded Polyethylene	5	5
Extruded polyvinyl chloride	1	3
Duck tape and asphalt	0	2
Other	3	5

twelve report that reductions are made; 8 use the AEIC value of 15 percent and the others specify reductions from 7 to 20 percent. When alloy lead sheaths are used, a greater percentage of utilities report reductions in sheath thickness under jackets, with 11 making reductions and 7 retaining full sheath thicknesses. Two reported reductions of 33 percent in thickness, and the remainder specify reductions of from 10 to 25 percent. In the 1950 report all types of lead were included in one answer, and 40 percent of the utilities reported reductions in the

(Text continued at top of Page 122)

TABLE 6—Value of Jacket On Lead Sheath Cables In Reducing Mechanical Damage Due To Cable Movement—Duct Lay Cable

Company		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	BB	CC	DD	EE	FF
Question 12	a																																
	b																																
	c						X																	X									
	d																					X											
	e		X								X																		X			X	X
	f	X		X	X			X	X	X		X	X	X	X	X	X	X		X			X			X	X	X				X	

TABLE 7

	Present Survey	1950 Report Data
Jacket of some value	1	4
Jacket of value	5	2
No tests or pertinent observations	19	20

TABLE 8—Coverings of Jacketed Lead Sheath Cables in Manholes

Company	Question 13	Question 14				Question 15						Question 16
		a	b	c	d	a	b	c	d	e	f	
A	Yes (13)	X							X			Yes
B	Yes (14)	X	X								X	Yes
C	Yes (13)	X	X								X	Yes
D		X	X								X	Yes
E	No										X	No
F	Yes (14)	X			(15)						X	Yes
G	Yes (16)	X									X	Yes
H	Yes (17)	X									X	Yes
I	No										X	Yes
J	Yes (18)	X	X								X	Yes
K	Yes (19)	X									X	Yes
L	Yes	X									X	Yes
M	Yes (20)	X									X	Yes
N											X	
O	No										X	Yes
P	Yes	X									X	Yes
Q	Yes (21)	X			(15)						X	Yes
R	Yes (22)	X									X	Yes
S	Yes (16)		X								X	No
T												
U	Yes (23)	X	X								X	Yes
V	Yes	X									X	No
W	Yes	X						X				Yes
X												
Y	Yes	X									X	Yes
Z	Yes (24)	X			(25)						X	No
AA	Yes (26)	X									X	No
BB	Yes (13)	X									X	Yes
CC												
DD												
EE	Yes (27)		X								X	No
FF	Yes (28)	X	X								X	Yes

(13) Rubber and neoprene tapes.
(14) Glass and neoprene tapes.
(15) To prevent expansion due to internal pressure.
(16) No-Ox-Idized tape No. 5.
(17) Neoprene tape.
(18) Neoprene tape plus a protective tape.
(19) Neoprene tape and paint.
(20) Similar to cable covering.
(21) Pressure sensitive filament tape plus rubber tape plus PVC pressure sensitive tape.
(22) Polyken tape.
(23) Friction plus neoprene tape.
(24) Neoprene tape and rubber cement.
(25) To seal the end of jacket to prevent ingress of moisture between jacket and sheath.
(26) Compatable adhesive and tape covering.
(27) Use removed jacket plus neoprene tape.
(28) Scotch tape.

Questions for Table 1

1. Do you use lead-sheathed power cable which has some form of jacket protection over the sheath?

2. If your answer to 1 is "Yes," which of the following cable difficulties prompted the use of sheath protection? Where several apply, number in order of importance—1, 2, 3, etc. (a) Sheath damage from stray current electrolysis. (b) Sheath damage from local galvanic cell action. (c) Sheath damage from chemical action. (d) Excessive wear of cable sheath at duct edge and at supports. (e) Manhole bending failure. (f) Sheath damage from remote faults. (g) Damage during installation. (h) Others, describe briefly.

3. Do you believe that the use of protection over lead sheaths is justifiable for general application or for use only in locations where sheath trouble is anticipated? (a) For general application throughout your system. (b) For special application. (c) Others, describe briefly.

4. Please list voltage ratings of cables which are jacketed in your system (in KV).

5. Approximately what percentage of the lead-sheathed power cable you are now buying is jacketed?

6. Of the lead-sheathed power cable you will be buying, approximately what percentage would you estimate will be jacketed: (a) 5 years from now? (b) 10 years from now?

Questions for Table 4

7. Sheath protection may take several forms; which of the following do you currently install? (a) Reinforced neoprene. (b) Extruded polyethylene. (c) Extruded polyvinyl chloride. (d) Duct tape and asphalt. (e) Other, describe briefly (Armored cable excluded).

8. For neoprene jackets, do you specify that jacket thickness be in accordance with the following standards:

Cable Diameter	Min. Average Jacket Thickness
0 to 1.500″	.080″
1.501″ to 3.000″	.110″
Over 3.000″	.140″

9. For other jackets, do you specify that the jacket thickness be generally proportional to the cable diameter? (Please give particulars.)

10. Do you make it a practice to use a lead sheath thinner than AEIC specifies for unjacketed cable when you buy cable covered with a protective jacket? (a) Plain lead or copper bearing. (b) Alloy lead.

11. If the answer to 10 (a-b) is "Yes," please state here percentage reduction in sheath thickness usually employed. (a) Plain lead or copper bearing. (b) Alloy lead.

lead thickness under jackets, with an average reduction of 30 percent.

Value of Jacket on Lead Sheath Cables in Reducing Mechanical Damage Due to Cable Movement[6]

There seems to be very little change in the limited data available from utilities on the value of the jackets as mechanical reinforcement or in reducing sheath damage from longitudinal cable expansion and contraction. There is a similarity between the replies to the present survey and those from the 1950 Report, as shown in Table 7.

Covering of Jacketed Lead-Sheathed Cables in Manholes[7]

Twenty-three utilities reported that they cover the joint sleeve and the lead sheath from which the jacket is removed during splicing operations with corrosion resistant materials, and three utilities reported they do not. This represents a 15 percent increase in this practice over the 1950 Report. Neoprene tapes are now commonly used in this covering. Table 9 lists the reasons given for installing the covering.

Twenty-six utilities reported no tests or pertinent observations on the value of jackets as arc protection. One expressed the belief that the jacket is of some value and another that it is of doubtful value. This lack of faith in the arcproofing value of jackets is further borne out by the fact that 21 utilities cover jacketed cables in manholes with the usual arcproofing materials, with only six utilities reporting

[6] See Table 6 for details.

[7] See Table 8 for details.

TABLE 9

Reason	Present Survey	1950 Report Data
Protection against corrosion	13	18
Mechanical protection	8	7
To prevent expansion due to internal pressure	2	3
To seal end of jacket to prevent ingress of moisture between jacket and sheaths	1	
Arc protection	0	
Other	—	

Question for Table 6

12. Have you made any observations or tests which indicate the value of jackets as a mechanical reinforcement or value in reducing sheath damage from longitudinal cable expansion and contraction? (a) Jacket of detrimental effect. (b) Jacket of no value. (c) Jacket of doubtful value. (d) Jacket of some value. (e) Jacket of value. (f) No tests or pertinent observations.

Questions for Table 8

13. Where cables are used with jackets over the lead sheath, the jacket must be cut off the cable for several inches beyond the wipe of the cable joint. Do you attempt to "cover" the sheath between the cut end of the jacket and one joint wipe and/or beyond with corrosion resistant materials? (exclusive of commonly-used arc protective coverings.) Please describe below.

14. If you have answered "Yes" to the question above, is the covering for the purpose of (a) Protection against corrosion. (b) Mechanical protection. (c) Arc protection. (d) Other.

15. Have you made any observations or tests which indicate the value of jackets as arc protection? (a) Jacket of detrimental effect. (b) Jacket of no value. (c) Jacket of doubtful value. (d) Jacket of some value. (e) Jacket of value. (f) No Tests or pertinent observations.

16. Do you cover jacketed cables in manholes with the usual arc proofing materials?

Questions for Table 10

17. The installation of jacketed duct-lay cable in the usual types of underground conduits may require the use of special pulling lubricants. Indicate the lubricant which you use with the following types of jackets: (a) Neoprene. (b) Polyethylene. (c) Polyvinyl chloride. (d) Duck tape and asphalt. (e) Lead (no jacket). (f) Other.

18. The use of jackets may result in ultimate difficulty with cable removal. Have you had any jacketed cable in service in underground ducts where the jacket made cable removal difficult?

19. If answer to 18 is "Yes," describe jacket and manner by which jacket gave trouble.

TABLE 10—Installation and Removal of Duct Lay Jacketed Lead Sheath Cables

Company	Question 17 a	b	c	d	e	f	Question 18	Question 19
A	(29)				(30)		No	
B	(29)				(30)		No	
C	(29)						No	
D	(29)	(31)			(30)		No	
E	(30)						No	
F	(29)				(30)		Yes	(32)
G	(33)				(30)		Yes	(34)
H	(29)				(30)		No	
I	(35)				(30)		No	
J	(30)				(30)		Yes	(36)
K	(29)			(37)	(30)		No	
L	(38)						Yes	(39)
M						(29)	No	
N								
O	(33-35)	(33-35)			(30-33-35)		No	
P	(29)						No	
Q	(29)				(30)		No	
R	(30)	(40)			(30)		Yes	(41)
S	None	None					Yes	(42)
T								
U	(29-35)				(29-35)		No	
V	(33)				(33)		Yes	(43)
W	(29)				(30)		No	
X								
Y	(44)	(44)			(30)		Yes	(45)
Z		(40)			(30)	(29)	Yes	(46)
AA	(47)				(30)		No	
BB	(29)				(30)		No	
CC								
DD								
EE	(29)				(30)		No	
FF	(35)				(30)		No	

(29) Soap (eg., Ivory Snow), neutral flax.
(30) Grease (eg., Sun C802), with soapstone, car lube, Albany improved pulling compound, petrolatum, Amoco or Minortac compounds, Albany No. 626, Gulf grease.
(31) Water.
(32) Rubber base jacket blistered and swelled and tore on removal of cable.
(33) Albany RBR Compound.
(34) Jacket was composed of two layers of asphalt-impregnated duct tape. After some time in the duct, some portions of the tape rotted especially at points abraded during the pulling in operation. When attempt was made to pull out the cable, the tape became balled up, jamming the cable in the duct. This type of jacket was discontinued approximately 20 years ago.
(35) Mineralac No. 100, special neoprene pulling compound.
(36) Hessian and duct tape joints previously used deteriorated which jammed cable in conduit making it impossible to remove cable.
(37) Powdered graphite and water.
(38) Barnard.
(39) Duct tape and asphalt adhere to fiber duct especially after a cable failure.
(40) Albentonite, Bentonite clay.
(41) Thiokol installed 1944, non-leaded. Jacket came loose from cable and jammed cable in duct when removal was attempted.
(42) Duct tape-difficulty removing.
(43) A few cases of bad neoprene jacket has caused difficulty in removal of cable due to failure.
(44) Powder soapstone and graphite.
(45) Jacket pulled off and blocked duct.
(46) The jacket is made of alternate layers of self-sealing rubber tapes and impregnated cotton tapes, bitumen compound being used between each layer. On top is a hessian tape with a final coat of bitumen compound and powdered graphite to prevent sticking. After installation, heat and dampness caused the outer hessian to deteriorate. Furthermore, cyclical movement of the cable rucked up the jacket and in some instances, exuded bitumen compound anchored the cable to the duct. Upon pulling out the cable, the heavily damaged jacket usually bunches up in ridges, wedging the cable solidly in the duct, and necessitating the demolition of the conduit to enable removal.
(47) Wire—eze.

that they do not arcproof jacketed lead-sheathed cables.

Installation and Removal of Duct Lay Jacketed Lead-Sheathed Cables[8]

All utilities which replied to this question, with one exception, report the use of lubricants for pulling cables into ducts. A wide variety of lubricants are used. Grease of some type is the most commonly used lubricant on bare lead-sheathed cables as is soap for neoprene jacketed cables. A list of the lubricants for jacketed and unjacketed lead-sheathed cables with the number of utilities using them is contained in Table 11.

Nine utilities reported difficulties in the removal of jacketed cable from ducts. The troubles experienced by five utilities involved jackets which included duct tapes or hessian and asphalt in their composition. Other troubles reported were:

1. Rubber base jacket deteriorated and tore on removal of cable.
2. Thiokol jacket came loose and jammed duct on attempted removal.
3. A few cases of bad neoprene caused removal difficulties (one utility).
4. Jacket pulled off and blocked duct.

Value of Lubricants as a Protection Against Corrosion of Lead-Sheathed Cables in Ducts[9]

Some utilities expect the grease which is used to lubricate unjacketed lead-sheathed cables during installation to help reduce corrosion troubles; five report the use of a grease with a corrosion inhibitor added to it and eight additional utilities believe a plain grease will help minimize corrosion. The greases are generally applied by hand during the installation of the cables. Only two utilities gave data on reduced sheath corrosion ascribed to the lubricant, as follows:

"In mildly corrosive areas, the number of corrosion failures has been reduced to 20 percent. In severely corrosive areas, the grease has no beneficial effect."

"Cables pulled out due to corrosive failures appear to be more severely pitted where pulling compound is thin or absent."

[8] See Table 10 for details.
[9] See Table 12 for details.

TABLE 11

Neoprene	
Soaps	13
Greases	3
Albany RBR Compound	3
Mineralac No. 100, special neoprene pulling compound	4
Barnard Compound	1
Powdered soapstone and graphite	1
Wire-eze	1
Polyethylene	
Albentonite, Bentonite Clay	2
Water	1
Albany RBR Compound	1
Mineralac No. 100 Compound	1
Powdered soapstone and graphite	1
Polyvinyl Chloride	No Replies
Lead (Unjacketed)	
Grease	19
Soap	1
Albany RBR Compound	2
Mineralac No. 100 Compound	2
Duck Tape and Asphalt	
Powdered graphite and water	1
Other Types	
Soap	2

Jacketed Lead-Sheathed Buried Cable

Extent of and Reasons for Use[10]

Ten of the reporting utilities use jacketed lead-sheathed cable for direct burial at voltages from 4 to 115 kv. Reasons for using this type of cable are listed in Table 14, using the same method of weighting replies as was used with duct lay cables to indicate the relative importance the industry gave to each reason.

The overriding emphasis is on the value of jackets as corrosion protection. Other properties of the jacket apparently have no important influence in determining their use for buried installations.

Six utilities expressed the belief that the general use of jacketed lead-sheathed cables for direct burial throughout their system is justified, while seven believe its use is justified only for special applications. Table 15 shows the extent that reporting utilities use jacketed cables for direct burial.

Three utilities indicate that the percentage of jacketed lead-sheathed cable used in their systems for direct burial will increase in the future. Two utilities reported they expect to continue to use jacketed cables exclusively in their systems. Two others, which reported using the smallest percentages at the present time, do not expect the percentage to increase.

Three utilities reported the use of buried lead-sheathed power cable in their systems which is neither jacketed nor armored.

Types and Thicknesses of Jackets; Thicknesses of Lead Sheath Under Jackets for Buried Cable[11]

The only type of jacket reported used on buried cable in the United States was neoprene with seven utilities specifying its use. Six of these require that the jacket thickness be in accord with industry standards. One Canadian utility reported the use of a rubber-bitumen sandwich, sometimes with a Mylar layer. The thickness of this jacket is not changed for differing cable diameters.

Six utilities answered that they reduce the thickness of the plain or copper bearing lead sheath when a jacket is used whereas three reported no reductions. Three use the AEIC specified reduction of 15 percent. The others reported reductions of from 7 to 20 percent. Of those which use alloy lead sheaths, two reduce sheath thickness by 15 and 20 percent respectively and two make no reductions.

Covering of Buried Cable Joints[12]

All of the utilities which use buried jacketed cable, with the exception of one which did not answer this question, reported covering the joint sleeve and the lead sheath which is exposed during splicing operations with corrosion resistant materials. Generally, neoprene tapes are

[10] See Table 13 for details.

TABLE 12—Value of Lubricants as a Protection Against The Corrosion of Lead Sheath Cables In Ducts

Company	Question 20 a	b	c	d
A	No	Yes	(48)	None
B	No	No		
C	No	No		
D	Yes	No	(48)	None
E	No	No		
F	No	Yes	(48)	
G	Yes		(48)	(49)
H	No	No		
I	Yes	No	(48)	None
J	No	Yes	(48-50)	
K	No			(51)
L	No	No		
M	No	No		
N	No	No		
O				
P		Yes		None
Q	No	No		None
R	Yes			
S	No	Yes		
T	No	No		
U	No			
V	No	Yes		
W	No	Yes	(48)	
X	No	No		
Y	No	No		
Z	Yes	No	(48-52)	None
AA	No	Yes		
BB	No	No		None
CC				
DD				
EE	No	No		None
FF	No	No		

(48) By hand as cable is installed.
(49) In mildly corrosive areas, the number of corrosion failures has been reduced to 20 percent. In severely corrosive areas, the grease has no beneficial effect.
(50) During cable reconditioning.
(51) Cables pulled out due to corrosive failures appear to be more severely pitted where pulling compound is thin or absent.
(52) Inhibitor is incorporated in the grease and a thin coat is applied at the factory before shipping.

[11] See Table 16 for details.
[12] See Table 17 for details.

Question for Table 12

20. Some users of lead-sheathed duct-lay cable have found that special lubricants for use with bare lead-sheathed cable can be formulated which will act as a corrosion inhibitor as well as a pulling lubricant.

(a) Do you use a corrosion inhibiting pulling grease in the installation of lead-sheathed duct-lay cable?
(b) Do you use a plain pulling grease, that is, one with no special inhibitor in it, with the expectation that it will help minimize corrosion?
(c) How do you apply greases intended to minimize corrosion?
(d) Also, please give a brief summary of any data which you have collected relative to increased sheath life ascribable to the lubricant.

included in this covering. Nine utilities reported this covering is primarily for corrosion protection, one indicated it had a secondary value as mechanical protection, and another that it also helped prevent expansion due to internal pressure.

Experience With Jacketed Lead-Sheathed Cable Duct Lay and Buried

Laboratory Data and Experience With Jacketed Lead-Sheathed Cables—Duct Lay and Buried[13]

Only two of the utilities which responded to this questionnaire reported the making of tests bearing on the life expectancy of jackets. One of these reported: "Soil burial tests extending over a 7 year period showed no deterioration of polyethylene or polyvinyl chloride jackets as indicated by decreases in insulation resistance of the jacket. Neoprene showed decreases in resistance." Another has been reporting periodic data on tests which are still in progress to the AIEE Insulated Conductors Committee. These data appear regularly in the November Minutes of that Committee starting in 1949.

There now appears to be a substantial amount of satisfactory field experience with jacketed cable, with one utility reporting 25 years of experience. The average experience of 18 reporting utilities is about 11 years. The following bear on the life which may be expected from jackets:

1. "Service experience from 1941 with rubber and/or neoprene with no failures —approximately 475,000 feet installed."

2. "Used PVC and reinforced rubber jackets in ducts beginning in 1939. Used reinforced neoprene since about 1944 both in ducts and buried."

3. "Practically no trouble with neoprene cable which has been our standard for 20 years."

4. "92,000 feet of duct lay cable in-

[13] See Table 18 for details.

TABLE 13—Extent of and Reason for the Use of Buried Jacketed Lead-Sheathed Cable

Company	Question 1	Question 2 a	b	c	d	e	f	Question 3 a	b	c	Question 4 4 to 5	12 to 15	17	24	33 to 35	69	115	Question 5	Question 5A	Question 6 a	b
A	Yes	3	2	1				X			X	X			X			95%	No	Increasing	Increasing
B	No																		No		
C																			No		
D	No																				
E																			No		
F	Yes		X	X				X				X			X				Yes		
G	No																		No		
H																			No		
I	No																		No		
J	Yes		2	1				X			X			X				(53)	Yes		
K	Yes		1						X							X		None	No	(54)	(54)
L	No																		No		
M	Yes	X	X	X				X			←			X			→	100%	No	100%	100%
N	Yes								X								X	(55)	No		
O	No																		No		
P	Yes		1	2	3				X			X						<1%	No	<1%	<1%
Q	No								X									None	Yes	75%	75%
R	No																				
S	No																				
T	No								X									None	No		
U																			No		
V																			No		
W	Yes		1	2				X							X			100%	No	100%	100%
X	No								X									None	No	0%	0%
Y	No																		No		
Z	No																		No		
AA	No																		No		
BB	Yes	2	1					X			X	X	X					30%	No	30%	30%
CC	No																				
DD	No																				
EE	Yes			X	X				X		X	X			X	X		90%	No	90%	90%+
FF																					

(53) 20 percent represents average purchases for last five years for both duct lay and buried applications.
(54) No plans for using protected sheath buried lead cable.
(55) Recently, purchased 8000 ft. 1/0—1/C—15 KV with poly. jacket for underground residential system part in transite duct, part direct burial.

TABLE 14

Reason	Relative Importance
Protection against sheath damage from local galvanic cell action	20
Protection against sheath damage from chemical action	16
Protection against sheath damage from stray current electrolysis	5
Protection from sheath damage from remote faults	3

TABLE 15

Number of Utilities	Percent of Lead-Sheathed Cable Purchased for Direct Burial Which Is Jacketed
2	100
1	95
1	90
1	30
1	More than 0 but less than 1

Questions for Table 13

1. Do you use lead-sheathed power cable which has some form of jacket protection over the sheath?

2. If your answer to 1 is "Yes," which of the following cable difficulties prompted the use of sheath protection? Where several apply, number in order of importance—1, 2, 3, etc. (a) Sheath damage from stray current electrolysis. (b) Sheath damage from local galvanic cell action. (c) Sheath damage from chemical action. (d) Sheath damage from remote faults. (e) Damage during installation. (f) Others, describe briefly.

3. Do you believe that the use of protection over lead sheaths is justifiable for general application or for use only in locations where sheath trouble is anticipated? (a) For general application throughout your system. (b) For special application. (c) Others, describe briefly.

4. Please list voltage ratings, in KV, of cables which are jacketed in your system.

5. Approximately what percentage of the lead-sheathed power cable you are now buying is jacketed?

5a. Do you have any buried power cable in your system which is neither jacketed nor armored?

6. Of the lead-sheathed power cable you will be buying, approximately what percentage would you estimate will be jacketed: (a) 5 years from now? (b) 10 years from now?

stalled since 1940 with two failures . . . No failures have occurred in 1800 feet of buried cable installed in 1940."

5. "We have installed over 1,000,000 feet of neoprene jacketed PILC cable (1948-1956) and to date have had very few failures."

6. "No jacket trouble in service due to aging (editor's note: 11 years experience)."

Experience with jackets, however, has not been completely trouble-free and without difficulties. It would nevertheless appear that many of the troubles listed below would not be associated with jackets made and installed in very recent years:

1. "Environmental cracking of polyethylene jacketed sheaths due to use of wrong pulling compound."

2. "Early jackets were poorly made and not well bonded to the sheath. Jackets made now are much better. Nonconducting jackets cause some increase in the hazard of potential difference between sheath and ground during failure."

3. "Jacket composed of . . . asphalt . . . impregnated tape . . . tape rotted . . . jamming cable in duct."

4. "Some trouble has been experienced due to lack of adhesion of the jacket (editor's note: neoprene) to the lead sheath and separation of the component parts."

5. "Installing cable of larger over-all diameter in old duct lines due to increased size."

6. "Only difficulty has been avoidance of trouble in getting it into ducts."

7. "Removal of jacket for splicing and terminating is difficult. Possible sheath damage when cutting and scraping jacket from lead."

8. "Water blisters have formed under jacket and in cases of complete submersion neoprene had leaked out of tapes, leaving a rather deteriorated jacket."

9. "All failures were due to poor workmanship at jacket termination near splice."

10. "We have noted that outer neoprene impregnated cotton fabric tapes have rotted."

11. "Some trouble has been experienced in 69 kv M.P.G.F. cable due to moisture entering through jacket . . ."

12. "All troubles due to initially defective jackets, such as registered tapes, laminated neoprene wall, and longitudinal splits."

13. "The jacket is made up of . . . rubber tapes . . . cotton tapes . . . bitumen compound . . . hessian tape . . . bitumen . . . heat and dampness caused outer hessian to deteriorate . . . movement rucked up jacket . . . in some cases exuded bitumen anchored cable."

TABLE 16—Types and Thickness of Jackets and Thickness of the Lead Sheath Specified for Jacketed Lead-Sheathed Cables Used for Direct Burial.

Company	Question 7 a	b	c	d	e	Question 8	Question 9	Question 10 a	b	Question 11 a	b
A	X					Yes		Yes		15%	
B											
C											
D											
E											
F	X					Yes		Yes	Yes	15%	15%
G											
H											
I											
J	X					No		Yes		7 to 13%	
K											
L											
M					(56)		No	No	No		
N						Yes	Yes	No	No		
O											
P	X					Yes		Yes		10% ±	
Q											
R											
S											
T											
U											
V											
W	X					Yes		Yes		15%	
X											
Y											
Z											
AA											
BB	X					Yes		Yes	Yes	20% ±	20% ±
CC											
DD											
EE	X					Yes		No			
FF											

(56) Rubber-bitumen sandwich now most used, sometimes with a Mylar layer.

TABLE 17—Covering of Buried Cable Joints

Company	Question 13	Question 14 a	b	c	d
A	Yes (57)	X			
B					
C					
D					
E					
F	Yes (58)	X			(59)
G					
H					
I					
J	Yes (60)	1	2		
K					
L					
M	Yes (61)	X			
N	Yes (62)	X			
O					
P	Yes	X			
Q					
R					
S					
T					
U					
V					
W	Yes	X			
X					
Y					
Z					
AA					
BB	Yes (63)	X			
CC					
DD					
EE	Yes (64)	X			
FF					

(57) Rubber and neoprene tapes.
(58) Neoprene and glass tapes.
(59) Glass tape to prevent expansion due to internal pressure.
(60) Neoprene tape and a protective tape over joint.
(61) Covering equivalent to that on cable.
(62) Plicoflex tape.
(63) Rubber and neoprene tapes applied only if corrosive condition is likely.
(64) Replaced part of the removed jacket to fit gap to wipe and reinforced with neoprene tape.

Questions for Table 16

7. Sheath protection may take several forms; which of the following do you currently install? (a) Reinforced neoprene. (b) Extruded polyethylene. (c) Extruded polyvinyl chloride. (d) Duck tape and asphalt. (e) Other, describe briefly (Armored cable excluded).

8. For neoprene jackets, do you specify that jacket thickness be in accordance with the following standards:

Cable Diameter	Min. Average Jacket Thickness
0 to 1.500″	.080″
1.501″ to 3.000″	.110″
Over 3.000″	.140″

9. For other jackets, do you specify that the jacket thickness be generally proportional to the cable diameter?

10. Do you make it a practice to use a lead sheath thinner than AEIC specifies for unjacketed cable when you buy cable covered with a protective jacket? (a) Plain lead or copper bearing. (b) Alloy lead.

11. If the answer to 10 (a-b) is "Yes," please state here percentage reduction in sheath thickness usually employed. (a) Plain lead or copper bearing. (b) Alloy lead.

Questions for Table 17

13. Where cables are used with jackets over the lead sheath, the jacket must be cut off the cable for several inches beyond the wipe of the cable joint. Do you attempt to "cover" the sheath between the cut end of the jacket and one joint wipe and/or beyond with corrosion resistant materials? (exclusive of commonly-used arc protective coverings.) Please describe below.

14. If you have answered "Yes" to the question above, is the covering for the purpose of—(a) Protection against corrosion. (b) Mechanical protection. (c) arc protection. (d) Other.

'14. "Abrasion of jacket at duct entrances in manholes. Incompatibility of some jackets with oil (oil-filled cable lines)."

None of the utilities reported any laboratory data or field experience in regard to the effect of higher sheath temperatures on jackets. This question was intended to apply particularly to the thermoplastic jacket materials for conditions of sustained high fault-return current sufficient to raise the sheath temperature above the softening point of the thermoplastic.

Jacketed Aluminum-Sheathed Cable

There were three utilities which reported aluminum-sheathed power cable in their underground system or an installation planned at the time this questionnaire was circulated. The questions and answers are given below and in Table 19.

1. What are the characteristics of the cable installation in your system?

Description of jacket (material, construction, etc.).

Utility G: Extruded polyethylene jacket 0.080″ thick.

Utility M: Hot asphalt compound, 40 mil special self-vulcanizing rubber tape wound half-lap, hot asphalt impregnated 5 mil muslin tape, hot asphalt, 1 mil Mylar tape, two 15 mil neoprene-faced friction tapes. This was a specially thin wrapping to use existing ducts. Normally at least two layers of rubber and asphalt-cemented muslin would be used in a rubber-bitumen sandwich.

Utility Z: 1—.040″ bitumen-rubber tape, half lapped; 1—.005″ impregnated muslin tape, half lapped; 1—Coat of bitumen compound; 1—.040″ bitumen-rubber tape, half lapped; 1—Coat of bitumen compound; 2—.020″ neoprene skim friction tapes.

2. Do you have any underground aluminum-sheathed power cable which is jacketed?

All three of the utilities answered "no."

3. How are joint sleeves connected to cable sheath?

Utility G: The aluminum sheath is pre-tinned with a special solder, prior to solder wiping (40/60) the lead sleeve to the aluminum sheath of the cable.

Utility M: Wiped.

Utility Z: Plumber's wipe.

4. Describe the coverings over the joint sleeves, wipes (or welds), and immediately adjacent cable. If no coverings are used please note that fact.

Utility G: Two layers of 10 mil pressure sensitive polyvinyl chloride tape are wrapped over the joint sleeve, wipes and cable sheath.

Utility M: Equivalent to jacket on cable.

Utility Z: Neoprene tape with rubber cement.

5. What has your experience been with jackets over the sheaths and with the hand-applied protective coverings over joints in the manholes?

Utility G: No failures have occurred yet.

Utility M: Comment withheld.

Utility Z: (a) This kind of jacket has behaved poorly in presence of oil due to leaking wipes and insulators (oil-filled cables). It has swelled and become soft in the manholes. In conduits, the jacket was found in good condition when two lengths of cable were replaced.

(b) The hand applied neoprene taping over the joints was unsatisfactory. It was difficult to apply and to keep in place over the wipes. The cement allows moisture to penetrate under the covering.

TABLE 18—Data and Experience With Jacketed Lead-Sheathed Cables—Duct-Lay and Buried

Company	Question 21 a	Question 21 b	Question 21 c	Question 22	Question 23
A	No		4	No	None
B			16 (65)		None
C			8	No	None
D			6	No	(66)
E	No			No	None
F			18 (67)	No	(68)
G	Yes	(69)	25	No	(70)
H			10 to 15	No	None
I	No			No	None
J			22	No	(71)
K	Yes	(72)	17		(73)
L					
M	No		5 (74)	No	(75)
N					
O	No		1	No	(76)
P	No			No	None
Q	No		2½	No	(73)
R	No		10	No	(77)
S					
T	No			No	
U	Yes	(78)	9	No	(78-79)
V	No			No	(80)
W	Yes	(81)	11		(82)
X					
Y				No	
Z	No		6 (83)	No	(84-85)
AA					
BB	No			No	None
CC					
DD					
EE	No		9 (86)	No	None
FF	No		5	No	

(65) Service experience from 1941 with rubber and/or neoprene with no failures—approximately 475,000 feet installed.
(66) Enviromental cracking of polyethylene jacketed sheath due to use of wrong pulling compound.
(67) Used PVC and reinforced rubber jackets in ducts beginning in 1939. Used reinforced neoprene since about 1944 both in ducts and buried.
(68) Early jackets were poorly made and not well bonded, to the sheath. Jackets made now are much better. Non-conducting jackets cause some increases in the hazard of potential difference between sheath and ground during failure.
(69) Soil burial tests extending over a 7 year period showed no deterioration of polyethylene or polyvinyl chloride jackets as indicated by decreases in insulation resistance of the jacket. Neoprene showed decreases in resistance.

TABLE 19

	Utility G	Utility M	Utility Z
Cable dia meter over jackets	1.350″	2.04″	2.58″
Thickness of sheath	.065″	.070″	0.105″
Thickness of jacket	.080″	0.10″	0.200″
Duct lay or buried	Duct Lay	Duct Lay	Duct Lay
Circuit length	5000′	17,500′	1.3 mile

Questions for Table 18

21. (a) Do you have any laboratory data or service experience which bears on life expectancy for any or all of the various jacket materials? (b) If so, summarize briefly. (c) Give the number of years experience you have had with protective jackets over lead sheath cables, duct-lay and buried.

22. Have you any laboratory data or service experience which bears on the effect of high sheath temperatures on the life of the various jackets? This question is intended to refer particularly to the thermoplastic jacket materials for conditions of sustained high fault-return current sufficient to raise the sheath temperature above the softening point of the thermoplastic. If you have any such data, please give a brief summary.

23. List the common difficulties you may have experienced with jacketed cable and your appraisal of the seriousness of the trouble. This question applies to both duct-lay and buried cable.

(70) See Footnote (34). Table 10.
(71) Practically no trouble with neoprene cable which has been our standard for 20 years. Some trouble has been experienced due to lack of adhesion of the jacket to the lead sheath and seperation of component parts.
(72) 92,000 feet of duct-lay cable installed since 1940 with two failures. Cable installed in 1947 failed after 6 months due to damage to protective covering during installation. Cable installed in 1940 failed 11-6-56 due to mechanical damage. Protective covering was found to be badly deteriorated due to heat from leaking steam line. No failures have occurred in 1800 feet of buried cable installed in 1940.

Note: 5.6 failures per 100 mile of operation during 1956 compared to 8.9 failures per 100 mile of all cable.
(73) Installing cable of larger overall diameter in old duct lines due to increased size.
(74) Three years with directly buried cable.
(75) Only difficulty has been avoidance of damage to jacket in getting it into ducts. Our tendency now is toward directly buried cable, though even this must be carefully laid.
(76) Removal of jacket for splicing and terminating is difficult. Possible sheath damage when cutting and scraping jacket from lead.
(77) Water blisters have formed under jacket and in cases of complete submersion neoprene has leaked out of tapes, leaving a rather deteriorated jacket.
(78) We have installed over 1,000,000 feet of neoprene jacketed PILC cable (1948-1956) and to date have had very few failures. All failures were due to poor workmanship at jacket termination near splice.
(79) We have noted that the outer neoprene impregnated cotton fabric tapes have rotted after being pulled from a duct which normally would be under water. Upon again pulling cable back into the duct, the neoprene is not, therefore, protected by this fabric tape. We would recommend a type of outer fabric tape which would not rot.
(80) Some trouble has been experienced on 69 KV—M.P.G.F. cable due to moisture entering through jacket causing corrosion of the bronze reinforcing tapes and eventual rupture of the lead sheath after the tapes break.
(81) See November minutes of A.I.E.E. Insulated Conductors Committee starting in 1949 for test data. No jacket trouble in service due to aging.
(82) All troubles due to initially defective jackets, such as registered tapes, laminated neoprene wall, and longitudinal splits.
(83) Years experience:
(a) 6 years, sandwich of bitumen-rubber, muslin, neoprene skim friction tapes.
(b) 5½ years; sandwich of rubber, cotton, hessian tapes.
(c) 1¼ years; extruded polyethylene.
(84) See Footnote (46). Table 10.
(85) Abrasion of jacket at duct entrances in manholes. Incompatibility of some jackets with oil (oil-filled cable lines).
(86) First installation nine years ago in wet duct under sluice discharge of boiler, no trouble thus far. Nine years ago three miles of jacketed cables were buried in industrial chemical area, no trouble.

Corrosion of Nuclear Power Plant Tube Materials By Boiler Sludge*

By E. HOWELLS, T. A. McNARY and D. E. WHITE

Abstract

An investigation was made of the corrosion effects of a sludge accumulation on various pressurized water nuclear power plant tubing alloys. The tests were performed in small, vertical heat exchangers in which the heat transfer tubes were made of the test alloys and a thick layer of sludge was placed on the tube sheet. Tests were run for various lengths of time up to 12 months in order to gain corrosion rate information. Each unit was thoroughly examined by destructive metallographic methods.

Inconel was the material most resistant to the test environment with little corrosion effect in evidence. Type 347 stainless steel was next with surface etching and some random pitting up to 2½ mils deep. Croloy 16-1 was superior to Monel and carbon steel and rated below Type 347 stainless because it suffered more general pitting up to 2½ mils deep. Monel was still more severely corroded with preferential attack up to 11 mils deep occurring at crevice opening. Carbon steel suffered the deepest attack on all surfaces, which were severely roughened. 4.6.2

Introduction

THE PRESENCE of sludge is quite common in the steam generators of power plants. Such sludge usually consists of an accumulation of iron oxides and metallic copper with smaller amounts of copper oxides and other impurities from the secondary (feedwater) system. In conventional water-tube type power boilers, the sludge can be allowed to accumulate in a chamber from which it is removed by means of a bottom blowdown connection. In the steam generators used in nuclear power plants, however, removing sludge would be considerably more difficult because of the configuration of these units.

Steam generators for pressurized-water nuclear power plants are predominantly of the vertical-shell and U-tube design in which boiling occurs outside the tubes. The tubing is very closely spaced and provides a potential sludge trap, especially at the surface of the horizontal tube sheet. Bottom blowdown lines are generally ineffective in removing sludge from such a "forest" of tubing.

The corrosive effect of such sludge accumulations is relatively unknown. In nuclear power steam generators, this is of significance because of the importance of plant integrity and the difficulty that would be encountered in removing sludge from the surfaces. The purpose of the program described in this paper is to determine the corrosion resistance of various tube alloys to boiler sludge under steaming conditions.

The test specimens used for this study were actually heat exchanger models of the same general configuration as the steam generators currently used in nuclear power plants. General conditions of test were designed to simulate those attending the operation of pressurized water plants.[1,2] A heavy layer of actual power boiler sludge was placed on the surface of the horizontal tube sheet exposed to the secondary system at the start of each test. The tests were performed by operating the models as steam generators for periods lasting from one month to a year at conditions which simulate those that prevail in the full scale units. At the end of each test, the unit was examined metallographically to determine the location, nature, and extent of corrosion.

Test Apparatus

The test apparatus consisted of heat exchanger models in which heat was transferred from high pressure subsaturated to saturated water at lower pressure. Eight of nine models contained six active U-tubes and 25 dummy tubes; the ninth model contained eight active and 21 dummy tubes. The purpose of the dummy tubes was mainly to simulate the "forest" of tubes in a full-scale unit. There was approximately 0.7 square feet of heat-transfer surface based on the internal active tube surface. Six materials were studied during these tests: Inconel, Monel, Type 347 and Type 304 stainless alloy, carbon steel and Croloy 16-1. With the exception of one heat exchanger model (U-40-S), all were constructed as shown in Figure 1. Table 1 gives the materials used for the various components. Figure 2 shows the tube sheet and the relative position of the tubes; as can be seen, the ½-inch OD tubes are on a ¾ inch triangular pitch with a ¼ inch ligament between the tubes.

Heat exchanger U-40-S was constructed in a manner similar to the one shown in Figure 1, but it was designed for higher temperatures (750-950 F) and had a longer secondary shell. This unit was tested at The Twin Branch Plant of The Indiana and Michigan Electric Corporation. Its primary heat source was steam between 750 and 950 F.

Prior to installation, all tubes were examined by the Zyglo Pentrex technique for indications of pits and other defects; those with significant defects were discarded. The Type 347 stainless alloy tubes were resistance annealed at 1950 F after bending; the carbon steel, Inconel, Monel, and Type 304 stainless were used in the as-received condition shown in Table 1. The heat exchanger model (U-42-S) containing the Croloy 16-1 material was heat treated at 950 F for ten hours in an argon atmosphere after fabrication.

The secondary face of the tube sheets was fitted with 25 dummy tubes expanded into blind holes, and the open tube ends were sealed. The active tubes were installed with the tube support plates located approximately three and four inches above the tube sheet on the inlet and outlet sides, respectively. The clearance between the tube and the support plate was 0.005 to 0.010 inch. A retractable expander was used to expand all tubes, active and dummy, 0.0075 inch beyond contact, as measured by the increase in the ID of the tube. During and after final assembly welding of the heat exchangers, all welds were leak checked by either the soap-bubble technique or the mass spectrometer.

A primary circuit, which served as a source of pressurized hot water, was essentially a rectangular loop made with stainless steel piping. The water was circulated around the system with a canned rotor pump, and the instrumentation was such that the pressure and temperatures of the system were automatically controlled. The flow of primary water through the heat exchanger models was controlled with valves and measured by means of a calibrated orifice plate located in the outlet line of each unit.

The secondary system, shown in Figure 3, was made with carbon steel piping. The steam-water mixture from the heat exchanger flowed up a riser by natural circulation to a steam drum about ten feet above the heat exchanger where the steam separated and went to an air-cooled condenser. The water circulated down the downcomer at approximately 4500 lb/hr to the heat exchanger. The installation of a shield, as shown in Figure 1, had a twofold purpose. It served to direct the flow of the water downward in an annulus between the shield and shell. In addition it prevented the returning secondary water from making a direct sweep across the tube sheet, an action that would tend to wash away the sludge retained on the tube sheet surface. The steam condensate continued through a subcooler at the calculated rate of approximately 30 lb/hr, over three square feet of copper surface, and finally returned to the heat exchanger as feedwater. The metallic copper served to simulate a source of condenser corrosion products that could enter the heat exchanger with the feedwater.

Sampling stations were provided so that water samples could be taken from points of interest. These included the primary system, the secondary riser and downcomer, the heat exchanger model and the steam drum.

Test Procedure

Just prior to making the last flanged riser connection during the installation of the heat exchanger models, 450 grams of a mixture of a typical boiler sludge and ferric hydroxide (10:1 by weight) were made into a slurry and washed into the secondary system. The system was sealed and most of the water in the slurry was evaporated by allowing primary water at 250 F to circulate through the heat exchanger. Previous mock-up tests had shown that it was necessary to add the ferric hydroxide as a binder in order to retain a moist mass of sludge

*Submitted for publication March 11, 1960. A paper presented at the 16th Annual Conference, National Association of Corrosion Engineers, Dallas, Texas, March 14-18, 1960.

Howells

D. E. White

McNary

E. HOWELLS attended Western Reserve University, Cleveland, Ohio, and Columbia University, receiving a BS (Chemistry) in 1949. He was an analytical chemist at the Johns-Manville Research and Development Center, Manville, New Jersey, 1949-1951. He did graduate work in X-ray diffraction at Rutgers University, New Brunswick, New Jersey. Mr. Howells started at The Babcock & Wilcox Company Research and Development Center, Alliance, Ohio, in 1951 as an X-ray diffraction and spectrographic analyst. Presently, he is Test Engineer for water and liquid metal corrosion studies.

D. E. WHITE, now with International Nickel Co. Bayonne, N. J., was formerly an engineer with Westinghouse, Bettis Atomic Power Division. He was graduated in 1947 from the U. S. Merchant Marine Academy, Kings Point, New York, 1947, and served as an engineer on East Coast oil tankers. He also was graduated from Case Institute of Technology in metallurgical engineering. During the Korean War he served as an engineering officer in the U. S. Navy.

T. A. McNARY received a BS in metallurgy from Grove City College, Grove City, Pennsylvania (1953). He went directly to The Babcock & Wilcox Company Research Center upon graduation and is presently an associate metallurgist. The past two years have been spent primarily in the field of corrosion of heat exchanger materials in aqueous solutions.

about 1 to 1½ inches deep on the tube sheet surface.

The secondary system was purged with nitrogen gas and then the system was filled to the operating level with water treated (Water A in Table 1) as follows:

pH (adjusted with NaOH)	10.9 ± 0.3
$PO_4 \equiv$ (added as Na_2HPO_4)	250 ± 50 ppm
$SO_3 =$ (added as Na_2SO_3)	30-50 ppm
$SO_4 =$	0 ppm
Cl^-	< 2.0 ppm
Total dissolved solids	1000 ppm
Dissolved oxygen	Undetectable

For Model U-41-S, the water was treated (Water B in Table 1) as follows:

pH (NaOH)	10.9 ± 0.3
$PO_4 \equiv$ (Na_2HPO_4)	250 ± 50 ppm
$SO_4 =$ (Na_2SO_4)	225 ± 25 ppm
Cl^- (Synthetic sea water)	25-50 ppm
Total dissolved solids	1000 ppm
Dissolved oxygen	0.1 - 0.5 ppm

Chloride ion and dissolved oxygen were added to this latter unit to determine the chloride stress-corrosion resistance of materials to a combination of sludge, dissolved oxygen and chloride ion in the secondary water.

Reagent grade chemicals were used at all times to maintain the water chemistry. The synthetic sea water was prepared according to ASTM Specification D1142-52.

Before the primary water was allowed to circulate through the heat exchangers, it was allowed to reach the following conditions:

Pressure	2000 psig
Temperature	580-590 F

The primary flow was started and the secondary systems were operated at a temperature and pressure of 480-490 F and 600 psig, respectively. Heat was transferred at the approximate rate of 50,000 Btu/hr-ft² based on the internal active tube surface area, with the exception of heat exchanger U-40-S which had a heat flux of about 80,000 Btu/hr-ft.²

During testing of all units, numerous water samples were analyzed for pH, Cl^-, $PO_4 \equiv$, $SO_4 =$, $SO_3 =$ and dissolved oxygen. Adjustments to the defined chemical concentrations were made with concentrated chemical solutions, or in the case of high levels, by blowdowns. In the case of heat exchanger model U-41-S, the dissolved oxygen was controlled by continuously injecting oxygen-saturated water into its feedwater system. In all other units, care was taken to prevent leakage of air into the system; for instance, during downtime the secondary systems were slightly pressurized with nitrogen gas.

At the conclusion of each test, the heat exchanger model was removed for examination. Care was taken to keep the sludge deposit undisturbed while the heat exchanger was being dismantled for a preliminary examination. Some general observations were made, photographs taken, and the pH of the sludge was measured *in situ*. The heat exchangers were then given a very thorough metallurgical examination.

Metallurgical Examination

This examination began by visually inspecting the secondary surfaces to determine the amount and distribution of sludge deposits. The active tubes were then cut off at the level of the top of the dummy tubes (about 2 inches above the secondary face of the tube sheet) and the individual tube-to-tube-sheet junctions were cut out of the tube sheet. After cutting off the seal welds of the active junctions and the excess tube sheet material of the dummy junctions, two longitudinal cuts were made through the tube sheet on opposite sides of the tube so that the tube sheet sections could be separated from the tube without disturbing the crevice surfaces.

All components of the boiler were examined under a binocular microscope before descaling to determine the character and amount of deposits at various locations. Descaling was done in a 15 percent (by volume) solution of hydrochloric acid containing 0.4 percent Dowell A-74 corrosion inhibitor. All secondary and crevice surfaces were again examined at up to 30 diameters magnification and all observations of general surface conditions, type and extent of corrosion, etc. were recorded. Metallographic sections through pertinent locations were examined to determine the characteristics of the corrosion.

Results

General

As tested, the secondary surfaces of all boilers were covered with large amounts of sludge, although the thickness of the coating varied greatly among different surfaces and boilers. The thickness of the sludge layer ranged from ⅜ to 2 inches. In all boilers, the dummy tube surfaces were relatively clean, covered at most by a thin, loose film-like sludge deposit, whereas the active U-tubes had a dense, baked coating up to 1/16 inch thick (see Figure 4). The crevice surfaces of the tube-to-tube-sheet junctions were covered with a thin, black oxide film at all locations, but sludge had deposited only in the area near the crevice opening.

In general, corrosion of dummy tubes was significantly less severe than that of the active heat transfer surfaces. Also, the U-tube surface areas that had formed crevices with the support plates experienced some degree of preferential attack in all boilers. However, preferential corrosion did not occur on the crevice surfaces of the tube-to-tube-sheet junctions.

Type 347 Stainless Steel

Type 347 stainless steel served as the control material in this program and, as such, was included in all nine test units. In the one and three month tests, this material suffered no measurable corrosion penetration although its surfaces became quite dull and exhibited scattered, small spots of slight roughening. Three six month tests were made in which all tubes were of Type 347 stainless steel. In these boilers, corrosion of exposed tube surfaces consisted of general dulling and spots of slight surface roughening, together with significant pitting. The pitting had a maximum penetration of 2½ mils, but the pit density was relatively low (see Figure 5). In the five month test with chloride ion and dissolved oxygen in the secondary water, general dulling and roughening of the stainless steel tubing was appreciably increased, but the deepest penetration was only 2 mils. In addition there was no evidence of chloride stress-

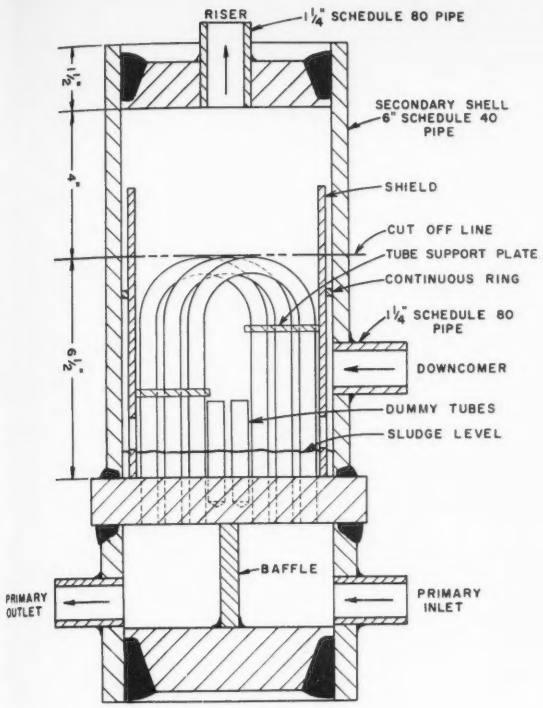


Figure 1—Sludge boiler.

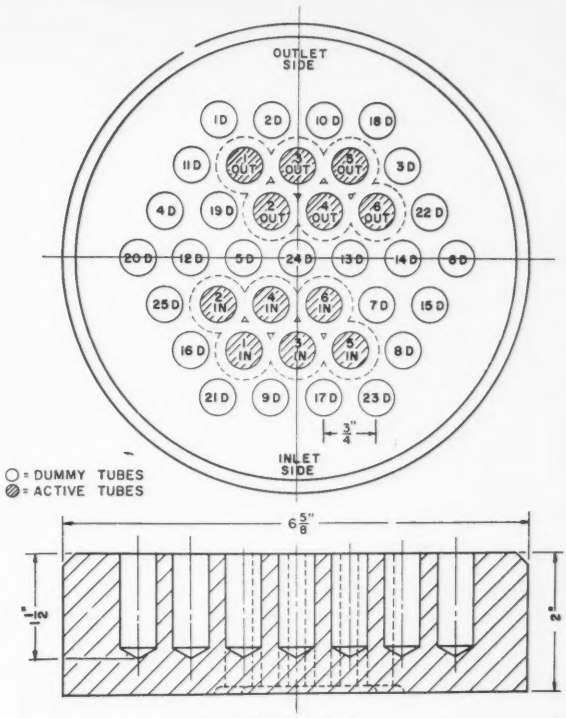


Figure 2—Tube sheet.

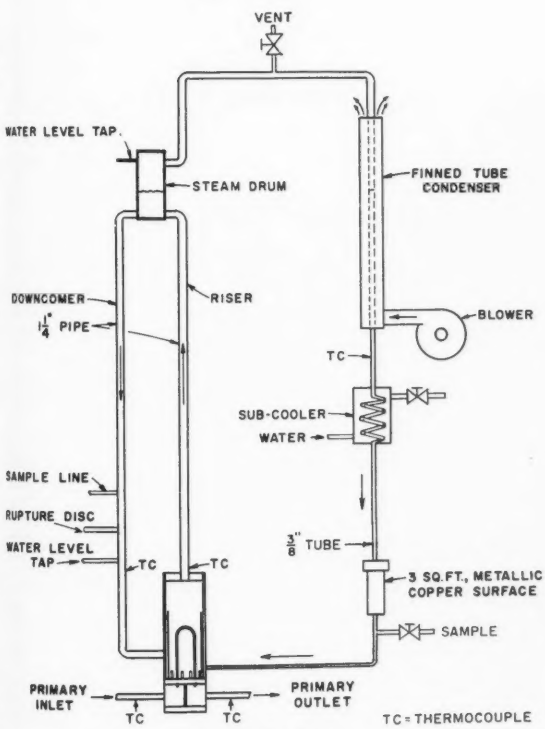


Figure 3—Test loop.

Figure 4—View of typical boiler model after test completion, showing distribution of sludge on secondary surfaces.

corrosion cracking. Corrosion of the stainless steel tubes in the one year test was very similar to that experienced in the six month tests. The maximum pit depth was only 1 mil. Several stainless steel tubes were included in the six month test of Croloy 16-1 and they experienced the usual general dulling and roughening together with the formation of a few scattered pits up to 1½ mils deep.

Inconel

Inconel tubing was included in five of the nine test units and, in all but one boiler, it displayed better corrosion resistance than did any of the other test ma-

TABLE 1—Heat Exchanger Materials and Test Conditions

DESIGNATION	HEAT EXCHANGER MODEL NUMBER U-22-S	U-23-S	U-24-S	U-34-S
ACTIVE TUBES 1	Type 347 Stainless[a]	Type 347 Stainless[a]	Type 347 Stainless[a]	Type 347 Stainless[a]
2	Type 347 Stainless[a]	Type 347 Stainless[a]	Type 347 Stainless[a]	Type 347 Stainless[a]
3	Type 347 Stainless[a]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[a]
4	Type 347 Stainless[a]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[a]
5	Type 347 Stainless[a]	Inconel[c]	Inconel[c]	Type 347 Stainless[a]
6	Type 347 Stainless[a]	Inconel[c]	Inconel[c]	Type 347 Stainless[a]
7	.....	.....	.....	.....
8	.....	.....	.....	.....
DUMMY TUBES 1D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
2D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
3D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
4D	Type 347 Staniless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
5D	Type 347 Stainless[b]	Type 347 Stainless[b]	Typr 347 Stainless[b]	Type 347 Stainless[b]
6D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
7D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
8D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
9D	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]	Type 347 Stainless[b]
10D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
11D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
12D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
13D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
14D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
15D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
16D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
17D	Type 347 Stainless[b]	Carbon Steel[b]	Carbon Steel[b]	Type 347 Stainless[b]
18D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
19D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
20D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
21D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
22D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
23D	Type 347 Stainless[b]	Inconel[e]	Inconel[e]	Type 347 Stainless[b]
24D	Type 347 Stainless[b]	Inconel[d]	Inconel[d]	Type 347 Stainless[b]
25D	Type 347 Stainless[b]	Inconel[d]	Inconel[d]	Type 347 Stainless[b]
TUBE SHEET	Type 304 Stainless	Carbon Steel, SA-105, Gr.II	Carbon Steel, SA-105, Gr.II	Carbon Steel, SA-105, Gr. II
SUPPORT PLATES	Type 304 Stainless	Carbon Steel	Carbon Steel	Carbon Steel
SECONDARY SHELL	Type 304 Stainless	Carbon Steel, SA-106, Gr. B	Carbon Steel, SA-106, Gr. B	Carbon Steel, SA-106, Gr. B
WATER CONDITION	A**	A	A	A
TEST TIME, MONTHS	6	1	3	6

[a] Resistance annealed at 1950 F-30 seconds.
[b] As received, from mill.
[c] Stabilized 1650 F-10 hours.
[d] Anneal 2000 F; Stabilized 1650 F 10 hours; Cooled in cracked ammonia atmosphere after each heat treatment.
[e] Anneal 1800 F 5 minutes at temperature in a continuous furnace; residence time up to 30 minutes.
* Dummy tubes replaced by active tubes.
** See text.

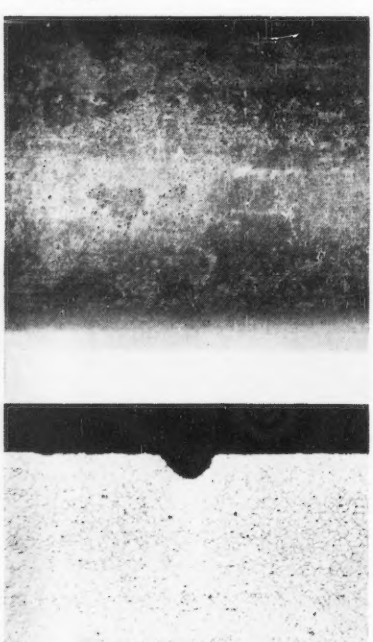


Figure 5—Top: view of Type 347 stainless steel U-tube from 6-month test, showing typical extent of roughening and pitting. Approximately 4X. Bottom: section through a pit in a stainless steel tube surface, showing general progression without respect to the microstructure of the material. Etchant: 70 percent HNO_3, electrolytic. Approximately 110X.

terials. In three tests of up to three months duration, Inconel tubing was affected only by slight general dulling and widely scattered, small spots of incipient surface roughening. In the five month test in which dissolved oxygen and chloride ion were present in the secondary water, general dulling and roughening of the exposed Inconel secondary surfaces were increased somewhat. In addition, the surface areas that formed crevices with the support plates experienced roughening and incipient pitting with a maximum penetration of 1½ mils (see Figure 6).

In Boiler No. U-35-S, which was operated for one year, most of the Inconel tube surface again was affected by only general dulling and scattered spots of slight roughening. However, there was pitting up to 2 mils deep in the bend regions of the Inconel U-tubes. The pits were nearly perfect hemispheres and very uniform in size. There was no similar corrosion on either of the other two test materials (Type 347 stainless steel and Monel) in this boiler.

Croloy 16-1

One six month test was made in which most of the tubing was of Croloy 16-1 material. Corrosion of the exposed secondary surfaces of this alloy consisted of considerable general roughening and randomly scattered pitting with a maximum penetration of 2½ mils (see Figure 7).

Monel

Monel tubing was installed in two of the nine boiler models and, in both units it suffered relatively severe attack. In the five month test with chloride ion and dissolved oxygen in the secondary water, Monel surfaces were considerably roughened at all locations and were preferentially attacked adjacent to crevice openings with a maximum penetration of 5 mils. In the 12 month test, Monel was essentially free of attack over the majority of the secondary surface but was subject to severe preferential corrosion (up to 11 mils deep) in the regions immediately adjacent to crevice openings (see Figure 8).

Carbon Steel

Carbon steel was used as a tube material in three tests and as a tube sheet material in eight boilers. In all tests, carbon steel secondary surfaces were severely roughened and pitted, with maximum penetrations varying up to 15 mils (see Figure 9).

Discussion

The authors believe that the heat exchanger model as a specimen offers a unique method of proof testing the corrosion resistance of materials to be used

TABLE 1 (Continued)

HEAT EXCHANGER MODEL NUMBER				
U-35-S	U-36-S	U-40-S	U-41-S	U-42-S
Monel[b] Monel[b] Inconel Inconel	Type 347 Stainless[a] Type 347 Stainless[a] Type 347 Stainless[a] Type 347 Stainless[a]	Type 347 Stainless[a] Type 347 Stainless[a] Carbon Steel[b] Carbon Steel[b]	Type 347 Stainless[a] Type 347 Stainless[a] Monel[b] Monel[b]	Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b]
Type 347 Stainless[a] Type 347 Stainless[a]	Type 347 Stainless[a] Type 347 Stainless[a]	Inconel[c] Inconel[d]	Inconel[c] Inconel[d]	Croloy 16-1[b] Croloy 16-1[b] Type 347 Stainless[a] Type 347 Stainless[a]
Monel[b] Monel[b] Monel[b] Monel[b] Monel[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b] Type 347 Stainless[b] Croloy 16-1[b]
Monel[b] Monel[b] Monel[b] Inconel Inconel	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Carbon Steel[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Monel[b]	Croloy 16-1[b] (Active-In)* Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b]
Inconel Inconel Inconel Inconel Inconel	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Carbon Steel[b] Carbon Steel[b] Carbon Steel[b] Carbon Steel[b] Carbon Steel[b]	Monel[b] Monel[b] Monel[b] Monel[b] Monel[b]	Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b] Type 347 Stainless[b]
Inconel Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Carbon Steel[b] Carbon Steel[b] Inconel[e] Inconel[e] Inconel[e]	Monel[b] Monel[b] Inconel[e] Inconel[e] Inconel[e]	Croloy 16-1[b] Croloy 16-1[b] Croloy 16-1[b] (Active-Out)* Croloy 16-1[b]
Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b] Type 347 Stainless[b]	Inconel[e] Inconel[e] Inconel[e] Inconel[d] Inconel[d]	Inconel[e] Inconel[e] Inconel[e] Inconel[d] Inconel[d]	Croloy 16-1[b] (Active-Out)* Croloy 16-1[b] Croloy 16-1[b] (Active-In)*
Carbon Steel, SA-105, Gr. II Carbon Steel Carbon Steel, SA-106, Gr. B A 12	Carbon Steel, SA-105, Gr. II Carbon Steel Carbon Steel, SA-106, Gr. B A 6	Carbon Steel, SA-105, Gr. II Carbon Steel Carbon Steel, SA-106, Gr. B A 2½ (High Temp)	Carbon Steel, SA-105, Gr. II Carbon Steel Carbon Steel, SA-106, Gr. B B 5	Carbon Steel, SA-105, Gr. II Carbon Steel, Lower Croloy 16-1, Upper Carbon Steel, SA-106, Gr. B A 6

in the construction of steam generators. The usual technique of exposing either stressed or flat specimens to a specific environment leaves much to be desired. With heat exchanger models, it is possible to duplicate shop procedures used in constructing a full-scale unit and to simulate actual operating conditions. During the studies described in this paper, the test specimens were exposed to the thermal, chemical, and hydraulic environments that would be experienced by an actual unit. During the testing of the models, considerable effort was expended in maintaining these conditions, and it is believed that the minor deviations from the test specifications had no significant effect on the test results.

Type 347 stainless steel tubing was included in every test to serve as a control material. Then if chemical excursions or other unusual conditions prevailed during any of the tests, comparative results would still be obtained because of the presence of a common control material.

Because it is known that austenitic stainless steels are susceptible to stress-corrosion cracking, it was considered desirable to run one test (U-41-S) with sludge, chloride ion, and dissolved oxygen in the secondary water to determine if this combination had an inhibitive effect or no effect at all. Contrary to what was expected, stress-corrosion cracks were not observed in the Type 347 tubing material used. The reason is not clearly defined, but it seems possible that the sludge deposits prevented concentration of chloride ion to take place in crevices or on tube surfaces. The effects of any galvanic protection offered by the carbon steel tube sheet must not be overlooked.

Figure 6—General appearance of Inconel tube from 5-month test with chloride ion and dissolved oxygen in secondary water. Note roughening of tube surface, especially at tube support plate location.

TABLE 2—Typical Sludge Analysis

Chemical Analysis	Pre-Test	Post-Test
SiO_2	0.6%	0.2%
Al_2O_3	0.8	3.0
Fe_3O_4	39.3	50.8
TiO_2	0.1	0.2
CaO	1.3*	0.2
MgO	0.4	0.4
Na_2O	0.8	0.1*
NiO	3.5	2.6
Cr_2O_3	<0.1*	0.1*
MoO_3	<0.1*	<0.1*
CoO	<0.1*	<0.1*
Mn_3O_4	0.3	0.4
Cu (Metallic)	47.4	40.4
ZnO	1.0*	<0.7*
PbO	0.1*	<0.1*
SnO_2	.....	<0.1*
ZrO_2	0.1*	0.1*
P_2O_5	1.2	0.8
SO_3	2.2	1.4
Cl	0.01	.....
X-Ray Diffraction Analysis		
Major Constituents	Fe_3O_4 Cu	Fe_3O_4 Cu
Minor Constituents	Cu_2O	Fe_2O_3
Density, Gm/cm^3	5.86	6.0
pH of Sludge Slurry (Wetted with Test Water A)	10.4	10.4 (In situ)

* Spectrographic analysis, all others by wet chemical methods.

One model (U-40-S) was tested at a higher temperature because industrial experience with sludge corrosion, including some tube failures, has been associated with higher temperatures than the 500-600 F range of pressurized water nuclear plants. It was realized that the test conditions of time and temperature used

Figure 7—View of Croloy 16-1 U-tube after 6-month test showing general roughening and scattered pitting. Approximately 3X.

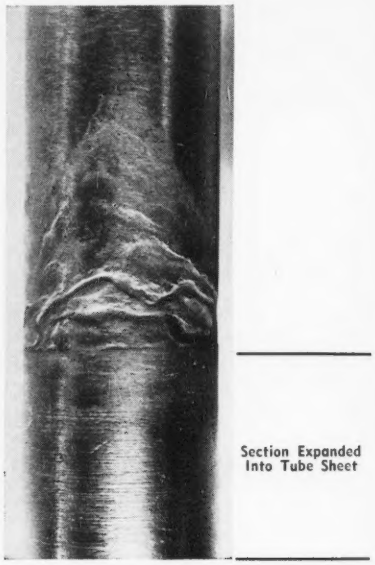


Figure 8—View of Monel tube from one-year test, showing severe preferential corrosion of area immediately above tube to tube sheet junction. Note that crevice area of tube surface is essentially unattacked. Approximately 2.5X.

Figure 9—Appearance of carbon steel tube from 2½-month test, showing general roughening and pitting. Approximately 3.5X.

during most of this program were not applicable to industrial experience, so this one high-temperature test was scheduled, in which it was expected that the corrosion effects would be somewhat accelerated. Although the observed corrosion was no more severe on this unit than it was on any of the others, the shorter test time would indicate that the rate of attack was somewhat greater. For instance, the deepest pits observed on the stainless steel tubing of Test Unit No. U-22-S at the end of 6 months was 2½ mils. In the high-temperature Test Unit No. U-40-S, at the end of 2½ months the pit depth in the same material was 1½ mils. A linear extrapolation of these data would produce corrosion rates of 5 and 7 mils per year, respectively. There are not enough data, however, to draw any firm conclusions in this respect.

Even though the sludge was inserted as a dense layer on the tube sheet at the beginning of each test, sludge deposits were observed on the uppermost portions of the heat transfer tubes—a distance of about 8 inches above the tube sheet. Including both the active and the dummy tubes, the tube spacing and density in the models were the same as would be used in full-scale units. Therefore, there is reason to believe that in a full-scale unit, if sludge does accumulate on the tube sheet, the stirring effect of thermal convection currents in an operating steam generator will cause sludge deposits to some considerable height on the tubes. In fact, the sludge that would be found in an actual plant would be more mobile than these tests would indicate because, as was pointed out in the procedure, $Fe(OH)_3$ was mixed with the sludge to hold it down. It is considered unlikely that the $Fe(OH)_3$ in any way affected corrosion.

Examination of the sludge before and after test (Table 2) revealed nothing unexpected; the sludge consisted mostly of Fe_2O_4 and metallic copper. At first it was considered possible that some of the observed corrosion effects might be due to chemical replacement of the iron in the iron-base alloys by copper ion in the solution. Close examination revealed that the copper was in the form of very small particles instead of being spread out on the tube surfaces. Therefore, it was considered more likely that presence of metallic copper *per se* had no observable effect on test results.

One of the most significant observations made on the components of the test units was that the sludge had a strong tendency to bake on or otherwise selectively deposit on heat transfer surfaces. There were distinctly more adherent deposits on the active tubes than on the dummy tubes. It was also observed that considerably more corrosion had taken place on the active tubes than on the dummy tubes. The increased corrosion under the heavier sludge deposits would indicate that the significant corrosion of the tubes in these model boilers was caused by the presence of concentration cells beneath the sludge deposits.

A review of all the data leads to the following conclusions:

1. The boiler sludge caused accelerated corrosion of the tube materials.

2. Heat transfer surfaces, which had more sludge deposit than inactive surfaces, were corroded more than those without heat transfer.

3. Type 347 stainless steel shows good resistance to corrosion by boiler sludge, but extrapolation of these results to very long operating periods in power boilers would have to be made with caution.

4. Inconel is superior to Type 347 stainless steel and all other alloys tested in sludge-containing boiler water even with chloride ion and oxygen additions.

5. The corrosion resistance of Croloy 16-1, although not as good as Type 347 stainless steel and Inconel, is superior to Monel and carbon steel.

6. Monel is inferior to Type 347 stainless steel with respect to corrosion resistance in sludge containing boiler waters.

7. Ordinary carbon steel is the least corrosion resistant of the alloys tested.

Acknowledgment

The authors acknowledge F. J. Pocock's special effort for control of water chemistry and various other chemical analyses in these tests.

References

1. W. J. Singley, I. H. Welinsky, S. T. Whirl and H. A. Klein. Stress-Corrosion of Stainless Steel and Boiler Water Treatment at Shippingport Atomic Power Station. *Proceedings of American Power Conference*, 21, 748-766 (1959).
2. J. H. Phillips and W. J. Singley. Screening Tests of Inhibitors to Prevent Chloride Stress-Corrosion. *Corrosion*, 15, 450t-454t (1959) September.

DISCUSSION

Question by F. W. Fink, Battelle Memorial Institute, Columbus, Ohio:

Was any chloride build-up found in the the sludge baked on to the boiler tube in the experiment where chloride, oxygen, etc. was added to the water?

Reply by E. Howells:

We did not make a post-test analysis of the chloride concentration in the sludge baked on the boiler tubes in the experiment where Cl^-, O_2, etc. was added to the water. Because the heat exchanger models were cooled to room temperature prior to removing from test, it is obvious that chloride would be present; however, it is not known if a build-up occurred.

Questions by E. A. Tice, The International Nickel Co., Inc., New York, N. Y:

1. Did I understand that no copper was found to be cemented out on any of the tubes after completion of the several tests?

2. Since the copper and copper oxide contributing to boiler sludge originates from the corrosion of the condenser and feedwater heater systems, in the conventional steam generating units, and since the feedwater system usually employs either cupro-nickel or nickel copper alloys, would you not also expect to find some nickel or nickel oxide in boiler sludge?

Replies by E. Howells:

1. We observed that no metallic copper was plated on any of the tubes after completion of the several tests. The elemental copper existed as small particles mixed with the sludge before and after test. It is on this basis that we have made the assumption that the presence of elemental copper *per se* did not contribute to the accelerated corrosion of the materials.

2. The corrosion of the condenser and feedwater heater system will add nickel, probably as the oxide, to the boiler sludge. A chemical analysis of the actual boiler sludge we used showed a nickel (as NiO) concentration of 3.5 percent; an X-ray diffraction analysis showed neither elemental nickel nor the oxide as being present in the crystalline state. No further study was made to determine the form in which the nickel was present in the sludge.

Question by C. L. Fitzgerald, Jr., Houston, Texas:

The condition of residual phosphate ion and boiler water pH were stated. I should like to know if free hydroxide ion was present under the stated test conditions?

Reply by E. Howells:

Although we did not analyze for free alkalinity (ASTM method) in the secondary water in these specific tests, we did so in previous work where the water treatment was essentially the same. In such cases no free alkalinity was found. It is assumed, therefore, that no free hydroxide ion was present under the stated conditions in this work.

Any discussion of this article not published above will appear in June, 1961 issue.

NACE Guide for Preparation of Articles for Publication

Persons interested in submitting articles on corrosion for publication in CORROSION can obtain upon request a copy of the "NACE Guide for Preparation of Papers." Write to CORROSION, National Association of Corrosion Engineers, 1061 M & M Bldg., Houston 2, Texas.

High Temperature Furnace Corrosion Of Type 309 Alloy Steel*

By R. D. MERRICK

About the Author

ROBERT D. MERRICK is head of the Metallurgy Group at Esso Research and Engineering Co., Linden, N. J. He is an NACE member and has a BS in metallurgical engineering from Purdue University and an MS in chemical engineering from Newark College of Engineering.

Abstract

Severe corrosion occurred on the external surface of tubes and tube supports of 25 Cr-12 Ni alloy steel in a furnace operating at metal temperatures from 1600 to 2100 F. Corrosion to a depth of ½ inch occured in six weeks' time. This furnace was operating under normal firing conditions with little sulfur in the gas. An investigation of the problem has revealed that the metal loss of furnace parts was accelerated by contaminants fluxing the hot metal surfaces. 4.2.3

Introduction

TYPE 309 (25 percent Cr-12 percent Ni) alloy steel has been noted for its resistance to corrosion by high temperature flue gases. Its superiority in corrosion resistance over the higher nickel alloys such as Type 310 (25 percent Cr-20 percent Ni) and Incoloy (20 percent Cr-32 percent Ni) is generally accepted, particularly when some sulfur compounds are present. Recently, however, severe corrosion of the Type 309 alloy by flue gas in high temperature refinery furnaces has been experienced. In these same furnaces the higher nickel alloys showed adequate corrosion resistance. Although the exact cause of the high corrosion rates has not been established, it is hoped that this discussion of the circumstances surrounding the failures will arouse interest in further study of the performance of these materials in high temperature flue gas environments.

Description of Failure

The furnaces were of a radiant type with a single row of horizontal tubes located in the center of the firebox. These tubes were supported at six foot intervals by cast, vertical "H" beams with the tubes passing through the web of the beam. About 100 reradiating gas burners were located on each side of the box about 3 feet from the tubes. The design metal temperature for the tubes and supports varied between 1600 and 2100 F. Since the fuel gas was expected to contain a high concentration of hydrogen sulfide, Type 309 (25 percent Cr-12 percent Ni) alloy steel was selected for the tubes and supports. The higher nickel alloys were excluded because of the expected high corrosion rates with the high sulfur fuel gas.

After seven months' operation, severe corrosion of both the tubes and supports had occurred as shown in Figures 1 and 2. Corrosion was in the form of tubercles on the tubes in a random pattern. On the supports large areas or the whole support were deteriorated and wasted away. The corrosion product was gray in color with a metallic appearance. On the tubes the deposits were roughly circular, ranging in diameter from ⅛ to 1¼ inch and in height from 1/16 to 1 inch. A large accumulation of deposit is shown in Figure 3.

When the gross deposits were removed from the tubes, deep pitting was uncovered. The pits were smooth and round bottomed, ranging in depth from 1/16 to ½ inch. Usually a tenacious sub-scale remained in the pits. In some of the areas of lesser attack, a reddish-brown dust adhered to the tubes. Under the dust there were the beginnings of pits characterized by a rough scale-like formation. Pitting of varying severity was found over approximately 20 percent of the total tube footage.

Attack of the support columns was essentially the same as that of the tubes. The deposits tended to be flat and in some cases covered considerable area as in Figure 2. Corrosion occurred on both the flat face and the edge of the beam flanges. As might be expected, the location and degree of attack on the supports corresponded with similar locations and degree on the tubes. The area of most severe attack occurred in the center of the furnaces.

Analysis of Failure

Nature of Attack

The corrosion product appeared to have been molten or near its melting point during operation of the furances. This is typical of severe high temperature corrosion. This type of corrosion product is also found where a fluxing agent is present which will form a low-melting compound or slag with the base metal or the normally protective oxide film. A typical example was recently reported by Moore.[1] Welding slag left on 34 percent Ni-21 percent Cr furnace tubes became molten at firebox conditions and caused severe metal loss by dissolving the base metal. Although a similar mechanism was suspected, it could not be supported by normal oper-

★Submitted for publication April 29, 1960. A paper presented at the 16th Annual Conference, National Association of Corrosion Engineers, Dallas, Texas, March 14-18, 1960.

Figure 1—Type 309 alloy steel furnace tubing after seven months' operation. Corrosion products have been removed.

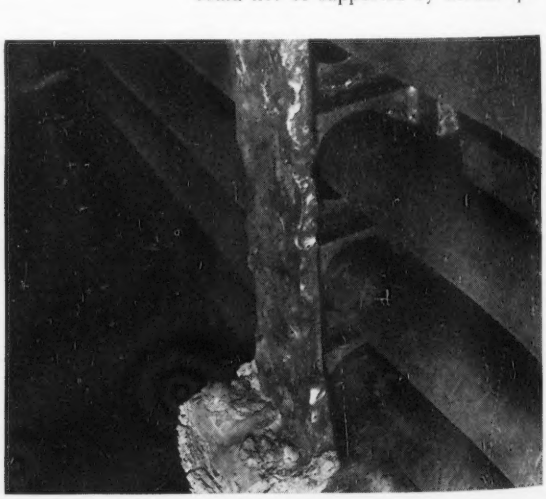


Figure 2—Tubes and tube supports after seven months' service.

Figure 3—Typical large tubercle of corrosion product in place on tube.

ating conditions. A close review of the actual firebox conditions was required.

Firebox Conditions

A number of interesting variables were found when reviewing the operation of the furnaces. The furnaces were designed to operate at fully oxidizing conditions. However, it was found difficult to maintain an excess of oxygen in all parts of the furnace. Representative flue gas analyses are given in Table 1. While these analyses are typical of reducing flue gases, they should be considered as mildly oxidizing to the metals present in the furnace.

Fuel gas for the furnaces varied considerably in sulfur content. Hydrogen sulfide ranged from 0.2 to 6.8 mol. percent in the fuel gas. No difference in severity of corrosion could be noticed between furnaces operating at the different sulfur levels.

During startup and initial operation, two conditions occurred that may have influenced the corrosion experienced. In order to observe draft conditions and flame pattern in one furnace, a "bronze powder" was injected through the primary air of some burners. The "bronze powder" consisted of copper and zinc with a 0.7 wt. percent fatty acid carrier. This material was used extensively during startup and periodically throughout a seven-month run.

The second condition involves painting of the furnaces while onstream. The outside of the furnace near the burners was spray painted while the burners were inspirating air at a rate of about 4500 cfh per burner. The painting contractor remembered he had a difficult time and "really had to pour it on." A unit operator observing the firebox at this time saw the paint enter the furnace by a change in the flame color. The paint pigment contained approximately 50 percent titanium and 50 percent chromium with 0.05 percent vanadium. To confirm that paint did enter the furance, samples of deposits found in the burners and samples of the refractory block were taken for analysis. Spectrographic analyses of the burner deposits showed about 50 percent titanium. The analysis of the refractory is show in Table 2. The high quantity of titanium on the surface of the refractory block confirms that paint entered the furnace.

Analysis of Corrosion Products

In an attempt to establish the presence of a "foreign" material which may have accelerated attack, chemical analyses of the corrosion products from both the tubes and supports were made. These are reported in Table 3. The analysis is as expected from high temperature oxidation of 25 percent Cr-12 percent Ni alloy steel. It should be noted that there is essentially no sulfur present. Copper is present in about the same concentration as in the base metal. Of possible significance is the rather high concentration of titanium, considering there is no titanium in the original alloy. The scales from both the tubes and supports were of the same composition. Chemical analyses also confirmed that the tubes and supports where of Type 309 alloy steel.

As mentioned above, a tenacious subscale remained on the tubes when the gross deposit was removed. Analyses showed no difference in composition between these two deposits. An attempt to obtain the analysis of the subscale *in situ* at the base of the pit with an electron probe was unsuccessful. The electron probe is an instrument that will give the X-ray diffraction pattern of a material in an area as small as one square micron.

Material Tests

Coincident with the investigation of firebox conditions, exposure of test pieces of different alloys was made in the furnaces. The corrosion rates are given in Table 4. The test pieces shown in Figure 4 were in the furance for approximately three months. As expected, the 18 Cr-8 Ni sample was destroyed by oxidation. The 25 Cr-20 Ni sample showed considerably greater resistance than the 25 Cr-12 Ni sample. The corrosion rates were 8.9 and 84.5 mils per year, respectively. The higher nickel alloys showed a similar good resistance to attack. The sulfur content of the fuel gas was nil during this test period, which may have accounted for the good resistance of Incoloy and 30 percent Cr-42 percent Ni alloy. However, tests in a second furnace operating with the sulfur content of the fuel gas about 2 mol. percent still show the superiority of the higher nickel alloys.

In a single tube pilot plant furnace, designed to give the same firing conditions and metal temperatures as the commerical furnace, similar corrosion of a 25 Cr-12 Ni tube was experienced. The unit was under controlled reducing conditions for 14 days with a clean, sulfur free, fuel gas being fired. There were no "foreign" materials introduced into this furnace. However, it is possible that the flue gas may have entrained some materials from the floor of the furnace. During previous runs of this pilot unit under controlled oxidizing conditions, no corrosion was experienced.

Metallurgical examination of the tubes and supports showed no unusual conditions. The uncorroded surface showed no signs of carburization or decarburization. At the base of the corroded area there was intergranular attack to a maximum depth of 20 mils. It appeared that an intergranular attack occurred which lifted the grains from the base material. These grains were then converted to the oxide. No sulfides were present in the microstructure.

Discussion of Findings

The investigation of this failure did

TABLE 1—Flue Gas Analyses

GAS	SAMPLE A	B	C	D	E	Typical Analysis Oxidizing Gas
CO_2	8.4	...	9.8	5.0	4.2	16.7
CO	4.5	6.0	...	4.3	2.6	0
O_2	0.4—13.0	4.0	3.1	...	...	3.7
SO_2	.....	0.7	0.4	...	...	.....
H_2	.....	0.02	...	...	...	.....

TABLE 2—Titania in Refractory Block

LOCATION	Percent By Weight
Fired Surface of Refractory	50
¼" Below Fired Surface	5
Unexposed Refractory	2

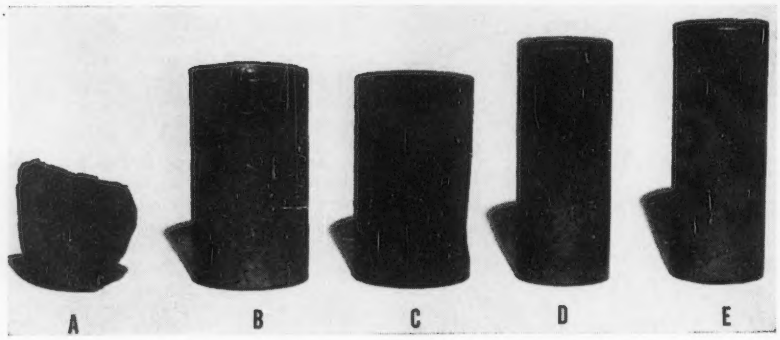


Figure 4—Samples after three months' furance exposure. Materials tested were as follows: A—Type 304; B—Type 309; C—Type 310; D—Incoloy; E—Type 804.

TABLE 3—Spectrographic and Chemical Analysis of Corrosion Product (Percent by Weight)

ELEMENT	Chemical Analysis (Sample 2)	SPECTROGRAPHIC ANALYSIS	
		Sample 1	Sample 2
Aluminum	.....	0.01	0.01
Chromium	21.30	10–100	5–10
Cobalt	.....	0.01–0.1	ND
Copper	0.03	0.01–0.1	0.1–0.5
Iron	Balance	10–100	10–100
Lead	.....	ND*	ND
Lithium	.....	ND	ND
Magnesium	.....	ND	ND
Manganese	.....	0.5–1	0.5–1
Molybdenum	.....	0.5–1	0.5–1
Nickel	12.60	5–10	5–10
Sodium	.....	ND	ND
Silicon	1.14	0.5–1	0.5–1
Titanium	.....	0.1–1	0.1–1
Tungsten	.....	ND	ND
Vanadium	0.02	0.05–0.1	0.05–0.1
Zinc	Nil.	ND	ND
Chlorine	.....	.....	0.01–0.1
Sulfur	0.006	.....	Nil.

* ND—Not Detected.

TABLE 4—Results of Corrosion Tests in Furnace Box

Alloy	Composition	Corrosion Rate Mils Per Year
Type 304	18 Cr- 8 Ni	Complete Oxidation
Type 309	25 Cr-12 Ni	84.5
Type 310	25 Cr-20 Ni	8.9
Incoloy	20 Cr-32 Ni	6.0
Type 804	30 Cr-42 Ni	9.7

Temperature—1600 to 2100 F.
Time of Exposure—3 months.

not disclose any single outstanding factor responsible for the accelerated corrosion experienced on the Type 309 alloy steel. Factors which may have influenced the rate of attack are:

1. Reducing flue gas.
2. High sulfur content in the flue gas.
3. "Foreign" materials in the flue gas.

Common to all furnaces was the presence of a reducing flue gas. The flue gas analysis from the stack and adjacent to the tubes showed little to no oxygen but did show the presence of both carbon dioxide and monoxide. The absence of oxygen would indicate this to be a reducing atmosphere. However, with the quantities of CO_2 and CO reported, the gas must be considered oxidizing to the metal at the furnace temperatures.

At temperatures above 1800 F, the ratio CO_2/CO must be less than 0.4 to have reducing conditions for the alloy. The furnaces operated at CO_2/CO ratios as high as 2.0. Since the CO_2/CO ratio in truly oxidizing gases is very large (little to no CO present), it appears that as this ratio approaches reducing conditions (although still oxidizing), corrosion will be accelerated. This is further substantiated by two experiences.

In the pilot plant, furnace corrosion of Type 309 alloy steel was experienced after 14 days in a reducing environment, CO_2/CO approximately 0.2, while under strong oxidizing conditions corrosion was not experienced after 30 days. In subsequent operation on one commercial furnace, 40 percent excess air was used and little further attack occurred. It appears that a highly oxidizing environment is required to maintain the normally protective oxide film on this alloy. At mildly oxidizing conditions there is probably insufficient oxygen to maintain the film.

The presence of sulfur did not seem to be a controlling variable. Corrosion was experienced in both commercial furnaces with different sulfur content fuel and in the pilot plant furnace with no sulfur. Also, there was no correlation between severity of attack and sulfur content of the fuel in the commercial furnaces. Variations in temperature and firing conditions could have clouded this effect. Examination of the microstructure of the tubes did not indicate the presence of sulfides. However, the absence of sulfides in the corrosion product cannot be taken as proof. When shutting down the furnaces, the burners are cut out and all access doors opened. The tubes and supports are exposed to this highly oxidizing condition at temperatures above 1000 F for approximately 18 hours. It is known that during regeneration of catalytic reformers, the iron sulfide scale sometimes present on the catalyst bed will be converted to oxides at 1000 F in about eight hours. Sulfides that may have been present in these scales would likewise be expected to be converted to oxides.

As mentioned above, two materials "foreign" to a normal furnace atmosphere were found. The presence of these materials, bronze powder and titania, are believed to have accelerated the rate of attack. The mechanism would be that of a "fluxing" agent which would cause the protective oxide scale to become molten and thereby expose the base metal to continuing oxidation. Although no running of the corrosion product occurred, samples of this product when reheated in the laboratory were molten at furnace temperatures. An oxide skin could have prevented running. A specific instance can be cited to support this theory. In one furnace, identification numbers were painted on a tube during construction with a titania pigmented paint. Later these numbers were clearly defined by an excessive build-up of corrosion products.

The materials tests conducted in these furnaces subsequent to the corrosion failures pointed out the inadequacy of the 25 Cr-12 Ni alloy. In all tests conducted the superiority of the higher nickel alloys was evident. With 25 percent chromium present in the alloy, a minimum of 20 percent Ni was required for adequate corrosion resistance. With higher nickel contents, the chromium may be reduced without a sacrifice in resistance.

Conclusions

From the data available to date, the following factors are believed to have influenced the performance of the 25 Cr-12 Ni alloy steel in these furnaces.

1. The rate of corrosion of the 25 percent Cr-12 percent Ni alloy is increased in flue gases in the temperature range of 1600 to 2100 F as the gas approaches reducing condition. That is, as the ratio of CO_2 to CO in the flue gas decreases, the rate of corrosion increases. At ratios less than about 2.0, the alloy is no longer suitable for long term use.

2. The presence of sulfur in the flue gas did not appear to affect the rate of corrosion.

3. The rate of attack was probably increased by the presence of materials foreign to the firebox. Titania introduced from painting of the furnaces is suspected.

Reference

1. K. L. Moore, Corrosion of Furnace Tubes by Residual Welding Slag. *Corrosion*, 16, No. 1, 26t-28t (1960) Jan.

Factors Governing the Corrosion Testing Of Zircaloy-Base Fuel Alloys*

By S. KASS* and R. F. GESSNER*

Abstract

Some of the factors governing the high temperature water and steam corrosion behavior of a Zircaloy-2 alloy containing 6.3 weight percent uranium were studied. Corrosion was found not to be influenced by sample size, marking methods, or pre-corrosion exposure surface condition. The data further show that the corrosion resistance is markedly influenced by heat treatment, with the low temperature treatment resulting in less corrosion than the high temperature treatment. Tests were run on samples in 600 F water, 680 F water and 750 F steam. 6.3.20

Introduction

A NUMBER of investigators have presented information on the high temperature water and steam corrosion properties of zirconium-base alloys containing small additions of uranium.[1,2,3,4,5] The corrosion tests generally were carried out in stainless steel (AISI Types 304, 316 and 347) pressure vessels with water exhibiting a resistivity of 500,000 ohm-cm, a pH of 6 to 8, and a low gas content (less than 0.05 ppm of oxygen). The coupons were machined from hot-rolled strip to an arbitrarily chosen size, identified by suitable means, and, after surface cleaning, placed in the autoclave.

Upon completion of the corrosion test, the coupons were cleaned of all loose corrosion product, dried and weighed. Many of the techniques employed follow the procedure or were based upon experiences gained in the corrosion testing of the Zircaloys (zirconium-base alloys not containing uranium). It has been shown, however, that the corrosion behavior of the Zircaloys is greatly influenced by the manner in which the test is performed.[6] Thus, it was considered prudent to investigate the effects of testing methods on the corrosion of a Zircaloy-2 base uranium alloy.

Experimental Considerations

Experimental Factors

The following factors were included in the experimental design:

A. Test Temperature
1. 750 F (400 C) steam at 1500 psi
2. 680 F (360 C) water at 2708 psi
3. 600 F (316 C) water at 1543 psi

B. Sample Surface
1. As-machined
2. Etched in 39 percent HNO_3 - 3 percent HF (1 mil removed)
3. Etched in 39 percent HNO_3 - 3 percent HF (2 mil removed)

C. Sample Size
1. 1 inch x 0.5 inch x 0.1 inch.
2. 1 inch x 1 inch x 0.1 inch.

D. Identification Method
1. Vibratool
2. Stamping

E. Heat Treatment
1. 24 hr at 1742 F (950 C), water quenched
2. 24 hr at 1022 F (550 C), furnace cooled

F. Post-Test Cleaning
1. Rinsed
2. Scrubbed

G. Ingot Location
1. Location 1
2. Location 2

Three corrosion test temperatures were chosen to (1) simulate the operating temperature range for water-cooled nuclear reactors, (2) duplicate or overlap the temperature ranges of previously reported information, and (3) determine whether temperature variations enhance the efficacy of the other factors.

The role of sample surface preparation in evaluating the corrosion behavior of metals and alloys has been studied by many investigators.[7] For some alloy systems, disparate corrosion results are obtained when the surfaces are abraded, chemically polished or etched. Two methods of surface preparation were included in this study to semi-quantitatively determine the influence of surface condition on the corrosion of the zirconium-uranium alloy.

Two sample sizes were included in the investigation to ascertain whether the uranium bearing alloy is similar to the non-uranium containing alloys (i.e., the corrosion rates are independent of specimen dimensions.)

Sample identification marks are usually made by engraving or vibratooling. Although stencil stamping methods are known to be more rapid, they have not been used for fear of producing accelerated corrosion because of micro-surface cracks or distorted surface layers. This factor was included in the work to resolve the point.

Prior corrosion studies have shown the corrosion of zirconium-low uranium alloys to be markedly influenced by heat treatment with annealing at 1022 F producing better corrosion resistance than quenching from 1742 F.[1,2,3,4,5] Both thermal treatments were included in the study to determine whether the effects of the "external factors" are overcome by the high corrosion rate.

Reproducible estimates of scaling corrosion rates can be obtained only when all loose corrosion product is removed from the sample surface. The purpose of incorporating the post-test cleaning factor into the experiment was to demonstrate clearly the above prerequisite.

As a complete factorial design incorporating the above factors would require a minimum of 288 coupons (an excessively large number), a partial factorial design was selected. The design (Appendix 1) required 108 coupons, minimized the loss of sensitivity brought about by not subjecting all possible treatments to experimentation and minimized inter-strip inhomogeneities.

Experimental Procedure

Material

Four sections of strip representing two locations (referred to as locations 1 and 2) of a 30-lb Zircaloy-2, 6 weight percent uranium alloy ingot were sampled. The ingot was triple arc-melted in an argon-helium atmosphere, forged at 1600 F (871 C) and rolled at 1350 F (732 C) to 0.120-inch strips. Chemical analysis of the material is shown in Table 1.

Sample Preparation

A total of 108 samples was prepared from the four strip sections: 36 coupons measured 1 inch x 1 inch x 0.1 inch and 72 samples measured 1 inch x 0.5 inch x 0.1 inch. A minimum of 0.02 inch was removed from all surfaces by machining and the finish was 63 rms or better.

Pickling, when required, was performed at 80 to 100 F in a solution containing 39 percent nitric acid, 3 percent hydrofluoric acid, and 58 percent tap water (all volume percentages). After pickling, the samples were thoroughly rinsed in warm (80 to 120 F) tap water. Unpickled samples were thoroughly degreased in perchloroethylene. All specimens were washed in high purity, demineralized water prior to corrosion testing.

The high temperature treatment was performed in sealed Vycor bulbs which were evacuated to less than 0.03 micron of mercury and backfllled to 18 cm with argon. The low temperature treatment was performed in sealed, evacuated bulbs.

TABLE 1—Chemical Analysis of Test Alloy

Element	Concentration
Uranium	6.3%
Tin	1.3%
Iron	0.15%
Chromium	0.11%
Nickel	0.06%
Copper	20 ppm
Tungsten	52 ppm
Hydrogen	180 ppm
Oxygen	929 ppm
Nitrogen	53 ppm

*Submitted for publication February 8, 1960.

† Westinghouse Electric Corp., Bettis Atomic Power Division, Pittsburgh, Pa.

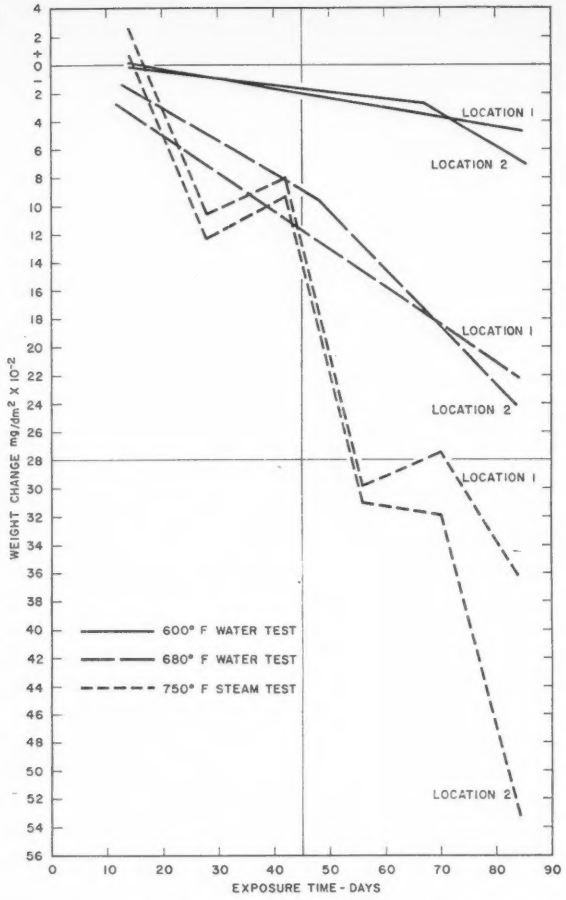


Figure 1—Effects of sample location on the corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

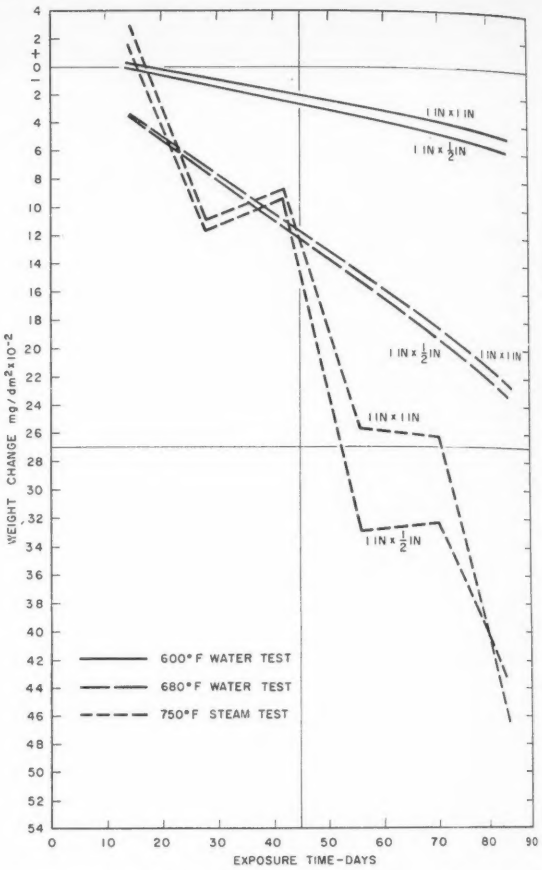

WEIGHT CHANGE mg/dm²x10⁻²
EXPOSURE TIME-DAYS
1 IN x 1 IN
1 IN x ½ IN
1 IN x ½ IN
1 IN x 1 IN
1 IN x 1 IN
1 IN x ½ IN
600°F WATER TEST
680°F WATER TEST
750°F STEAM TEST

Figure 2—Effects of sample size on the corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

TABLE 2—Corrosion Rates of Variables (mg/dm²-day)

Variables	TEST TEMPERATURE 600 F	680 F
Location		
1	—7.0	—26.4
2	—5.8—14.1	—22.4—40.9
Size		
1 inch x 1 inch	— 8.1	—26.2
1 inch x ½ inch	—10.1	—28.9
Identification		
Stamp	— 5.9	—30.4
Vibratool	— 8.8	—31.4
Surface Preparation		
As-machined	— 7.0	—33.5
1 mil pickle	— 6.6	—31.2
2 mil pickle	— 6.2	—28.1
Post-Test Cleaning		
Rinse	Erratic	—32.2
Scrub	Erratic	—29.6
Heat Treatment		
1022 F	— 3.3	—11.7
1742 F	—11.9	—50.1

Corrosion Testing

In general, corrosion test techniques similar to those established for corrosion testing the Zircaloys were followed.[6] The corrosion test medium was degassed high purity water or steam. Test temperatures were maintained at nominal ±5 F and pressures did not fluctuate greater than ±100 psi from the nominal. All weighings were made to an accuracy of ±0.2 mg. Specimens were removed from the autoclaves at 14-day intervals, loose oxide removed either by rinsing in warm tap water or scrubbing with a soft bristle brush under flowing tap water, weighed, and returned to test. Changes in specimen area due to metal loss from corrosion were not factored into the calculations.

Test Results and Discussion

The corrosion test results are expressed as mean weight changes for each of the experimental factors and are presented in graphical form. Corrosion rate constants attributable to each of the factors were determined by a method of least squares and are presented. Statistical analyses for significance were performed for the 14, 28, and 84-day cycles in the 600 and 750 F tests and for all cycles in the 680 F tests.

Sample Location

Weight changes attributed to sample location are presented graphically in Figure 1. The least squares rate constants are included in Table 2.

Some small differences are noted in the total corrosion as well as corrosion rates of the specimens representing the two locations in the ingot. For example, the corrosion rate for the location 1 samples in 600 F water is approximately constant at —7 mg/dm²-day while location 2 material exhibits an initial corrosion rate of —5.8 mg/dm²-day changing to —14 mg/dm²-day after 70 days exposure. Similar differences in the apparent corrosion resistance of location 1 and location 2 material are noted in 680 F water and 750 F steam with the exception that total corrosion losses and rates vary with temperature. Statistical analyses of the corrosion weight change data, however, show the differences are not significant at the 95 percent probability level.

Sample Size

Weight changes obtained from the specimens of the two sizes studied are depicted graphically in Figure 2. The rate constants are shown in Table 2.

The small (1 inch x 0.5 inch) samples exhibited slightly larger weight losses than the large (1 inch x 1 inch) samples, but the differences are not statistically significant at the 95 percent probability level. Corrosion rates for the large samples (—8.1 mg/dm²-day at 600 F and —26.2 mg/dm²-day at 680 F) are sim-

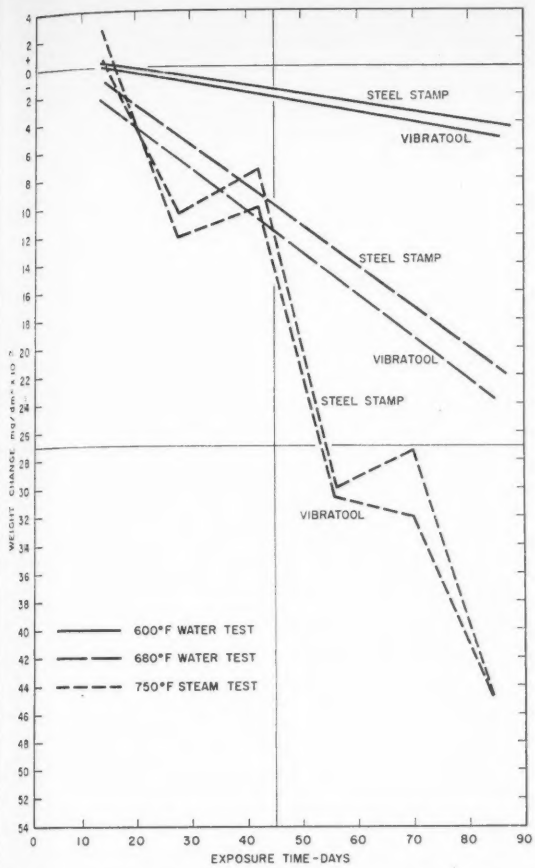


Figure 3—Effects of identification techniques on the corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

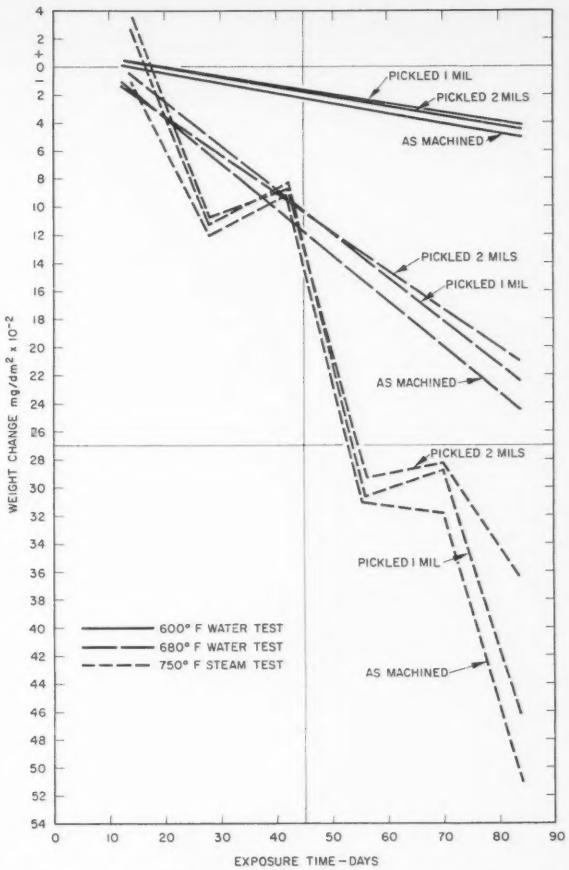


Figure 4—Effects of sample surface preparation on the corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

ilar to those of the small samples (—10.0 mg/dm²-day at 600 F and —28.9 mg/dm²-day at 680 F).

Sample Identification

The weight changes exhibited by the specimens identified by the steel stamping or vibratooling (surface scratching with a vibrating needle) methods are shown in Figure 3. The rate constants are listed in Table 2.

A statistical significance at the 95 percent probability level between the two marking methods was noted only in the first two cycles of the 680 F tests with the vibratooled samples exhibiting greater corrosion; all other test analyses showed both specimen identification techniques yield similar results. The overall corrosion rates of the specimens are markedly similar; thus, the long-term corrosion is unaffected by sample identification methods. (It should be noted that cracking of the specimens was not caused by the stamping methods used.)

When the corrosion was characterized by heavy spalling, the stamped specimens retained clear, easily recognizable characters while the vibratooled identifications became less discernible suggesting that deep marking should be employed (e.g., stamping, engraving, heavy vibratooling, etc.).

Surface Preparation

The weight changes due to the various pre-corrosion exposure treatments are depicted graphically in Figure 4. The corrosion rate constants are included in Table 2.

The corrosion weight changes and rate constants are not influenced by methods of sample preparation.

Post-Test Cleaning

Figure 5 shows the weight changes and Table 2 includes the corrosion rates of the scrubbed or rinsed samples. It should be noted that significantly higher weight losses are obtained when scrubbing is employed.

Complete removal of all loose oxide thus is a prerequisite for reproducible weight change or corrosion rate measurements, and mere immersion and agitation in a water bath is not sufficient for removal of the corrosion product. Scrubbing with a soft bristle brush has been demonstrated to be an effective method for the removal, although it may be impossible to assure that uniform scrubbing will be performed from coupon to coupon or cycle to cycle. In addition, the scrubbing action often results in a scattering of uranium oxide particles and presents health safety problems. A more uniform, reproducible and safe method for the oxide removal can be obtained by ultrasonic cleaning. The cavitation of the solvent removes loose oxide particles, and as the variables immersion time and applied power can be fixed, all human errors should be minimized. Preliminary experiments have shown that ultrasonic cleaning results in corrosion rates and weight changes comparable to scrubbing.

Test Media and Temperature

The effects of corrosion test temperature and media can be readily evaluated from the figures expressing the corrosion. In general, the corrosion resistance decreases with increasing temperature. The behaviors in 600 and 680 F water are quite similar but significantly different behavior is noted in 750 F steam.

The following will illustrate the similarities and differences:

1. The weight losses exhibited by the heat treatment combinations (Figure 6) after 56 days exposure were —86 and —354 mg/dm² at 600 F, —529 and —2240 mg/dm² at 680 F, and —1020 and —5046 mg/dm² at 750 F. Thus, the weight loss increases with increasing temperature.

2. Inspection of the figures show remarkable similarity in the general behavior of the alloy in 600 and 680 F water. (Note especially Figures 1, 2, 3, and 4.) Spalling, once initiated, proceeds at a

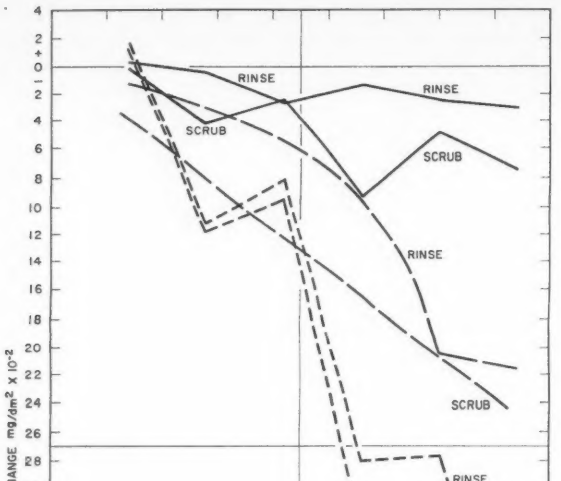


Figure 5—Effects of oxide removal techniques on the corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

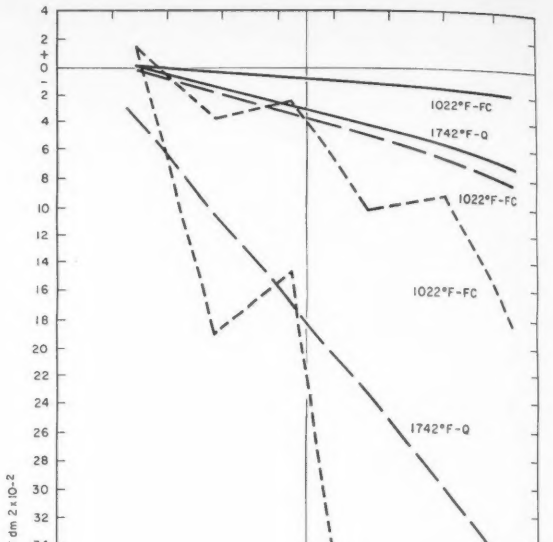


Figure 6—Effects of thermal treatment on corrosion of a Zircaloy-2 plus 6.3 weight percent uranium alloy.

uniform rate from cycle to cycle following a linear corrosion rate law, with the spalling rate increasing with increasing test temperature. On the other hand, a wide variation in cycle to cycle corrosion rates is observed in 750 F steam.

It has been previously reported[1] that the corrosion of low uranium-zirconium alloys is characterized by the initial formation of an adherent oxide film, followed by a breakdown of the quasi-protective kinetics resulting in loose, spalling oxide. This behavior is again noted in the 600 and 680 F tests; film breakdown occurs sooner in 680 F water than in 600 F water. The variation noted in the 750 F tests coupled with the magnitude of the weight changes suggests an oscillating-type corrosion. At the onset of corrosion in 750 F steam, a protective oxide film is formed. As the film grows, a deterioration of all or a portion of the oxide occurs and a spalling type film results. Upon removal from test, all loose oxide is removed by the scrubbing, exposing bare metal or a thin layer of protective oxide which, upon additional corrosion exposure, undergoes further deterioration and spalling. Thus a series of steps is noted when weight change is plotted against time.

It is also noted that weight gains are initially obtained in the 750 F steam test but not in the 680 F water test. This anomalous behavior may be brought about by either of the following means:

1. The 680 F test medium is liquid while the 750 F test is conducted in a vapor. In 680 F water, the liquid exerts a washing action on the specimens because of great turbulence resulting from the thermal gradients within the autoclave. This turbulence enhances erosion of the surface oxide. On the other hand, little if any turbulence exists in the vapor phase tests; hence, the erosive effects are small.

2. The mechanisms of corrosion in 680 F water are sufficiently different from those operating in 750 F steam. These kinetic differences may be attributed to the fact that the 680 F test is performed at 2708 psi while the 750 F test is performed at 1500 psi and it has been shown that the corrosion behavior of many materials is greatly influenced by the pressure of the corrosion media.[7] Perhaps the zirconium low uranium alloys can be added to the listing.

Heat Treatment

The weight change data for the heat treatment study are presented graphically in Figure 6. Corrosion rate data are listed in Table 2.

The material heat treated at 1022 F exhibits better corrosion resistance than when rapidly cooled from 1742 F, in agreement with previously reported data. The corrosion rates for the material heat treated at 1742 F increases from —11.9 to —50.1 mg/dm²-day as the test temperature is increased from 600 to 680 F while the 1022 F treated material increases from —3.3 to —11.7 mg/dm²-day.

A complete discussion of the effects of heat treatment can be found in References 3, 4, and 5; however, for the purposes of this report it should be

pointed out that the corrosion behavior of low uranium-zirconium base alloys is believed to be governed by the amount and distribution of the epsilon phase in the alpha zirconium matrix. The metallurgical structure after annealing at 1022 F is essentially alpha zirconium containing finely dispersed epsilson. The alpha coalesces and coarsens when the alloy is held isothermally at 1742 F (the alpha + beta phase region) resulting in a continuous heavy network of epsilon. Increased corrosion rates should be obtained as the epsilon network becomes more continuous.

Conclusions

1. Similar corrosion resistance of uranium-bearing Zircaloy-base alloys is obtained whether 1-inch x 1-inch coupons or 1-inch x 0.5-inch coupons are employed.

2. Machined specimens, prepared so as to minimize the possibility of smearing or contaminating the surface with air, may be tested without further surface preparation. Pickling in HNO_3-HF-H_2O may be employed if surface contamination from the tool or air is suspected.

3. Either steel stamps or a vibratool may be used for identification marking; however, during prolonged testing, the vibratooled characters may be obliterated. Engraving, essentially a machining operation subject to the same requirements of surface machining, would then be more suitable.

4. All loose oxide must be removed prior to weighing. Scrubbing or ultrasonic cleaning methods are satisfactory.

5. The corrosion mechanisms observed in 600 or 680 F water are different from those observed in 750 F steam. In water, a linear corrosion rate is noted; in 750 F steam, however, cyclic, alternatingly protective and spalling films are noted.

6. The corrosion behavior of Zircaloy-base fuel alloys is dependent upon prior thermal history. The alloys exhibit lower corrosion rates after slowly cooling from 1022 F than after fast cooling from 1742 F.

Acknowledgments

The authors wish to acknowledge the help of A. C. Nelson, Jr. and W. L. Davis of the Bettis Statistical Staff for the statistical design and analysis. The work of the Materials Department Corrosion Laboratory contributed greatly to this work. This work was performed and reported as a part of Contract AT-11-1-GEN-14 granted by the United States Atomic Energy Commission.

References

1. S. Kass. The Corrosion Properties of Zirconium-Base Fuel Alloys. Paper 57-NESC-3, Nuclear Engineering and Science Conference, March 1957, (also WAPD-136).
2. S. Kass. The Corrosion of Zircaloy-Base Fuel Alloys in High Temperature Water. AEC Report WAPD-TM-123, 1958.
3. W. E. Berry and R. S. Peoples. The Corrosion Behavior of Zirconium-Uranium Alloys in High Temperature Water. *Corrosion*, **14**, 414t (1958) Sep.
4. A. A. Bauer, S. Kass, and K. M. Goldman. Physical Metallurgy and Properties of Zirconium-Uranium Alloys. 1958 Geneva Conference, A/CONF/15/P/1785.
5. V. Merten and D. C. Belouin. Corrosion Behavior of Zirconium-Base Uranium Alloys. AEC Report KAPL-1570, 1956.
6. S. Kass. Corrosion Testing Zircaloy-2 and Zircaloy-3. AEC Report WAPD-T-744, 1958.
7. O. Kubaschewski and B. E. Hopkins. Oxidation of Metals and Alloys. Academic Press, New York, 1953, pp. 49 to 54.

APPENDIX

Experimental Design and Analysis

The design used in this investigation is presented in the Appendix Table. This design is a ½ and a ¼ fractional replication of the 24 portion (D, E, F, G) of a complete factorial experiment for small and large coupons respectively. The same combinations of D, E, F, and G were investigated for each test condition (A) and each level of sample surface (B). The confounding patterns are as follows:

small coupons	large coupons
$I = DEFG$	$I = DE = FG = DEFG$

The following restrictions and considerations led to the choice of this particular design.

1. The material available for experimentation was limited to 144 small coupons or 72 large coupons or some combination of the two sizes. In planning the statistical design it was desired to do most of the experimentation on the small coupons and obtain only token information on the effects of large coupons. The weights assigned to coupon size were arbitrary.

2. Based on previous experience of the non-homogeneity of errors and the large differences in the effects under investigation for the various test conditions, it seemed appropriate to consider each test condition (A) as a separate experiment.

3. The same design was repeated for each level of sample surface (B) to facilitate the design, analysis and interpretation of the results.

The two and three factor interactions involving sample surface were pooled as an approximation to the appropriate error term for the tests of significance involving the main effects and interactions of D, E, F, and G. This pooling resulted in 14 degrees of freedom for the error term. The effect of coupon size was investigated by a direct comparison of those small and large coupons that were subjected to common levels of the factors D, E, F, and G. All statistical tests of significance were based on a probability level of 0.95.

APPENDIX TABLE—Experimental Design

A	B	C	D	E	F	G
The same design was repeated for all levels of A and B.		1	1	1	1	1
		1	2	1	2	1
		1	1	1	2	2
		1	2	1	2	2
		1	1	2	2	1
		1	2	2	1	1
		1	1	2	1	2
		1	2	2	2	2
		2	2	1	2	1
		2	1	1	2	2
		2	2	2	1	1
		2	1	2	1	2

Where

A. Test Condition
1. 750 F steam at 1500 psi.
2. 680 F water at 2708 psi.
3. 600 F water at 1543 psi.

B. Sample Surface
1. As-machined.
2. Pickled 1 mil.
3. Pickled 2 mil.

C. Coupon Size
1. 1 inch x ½ inch x 1/10 inch (small)
2. 1 inch x 1 inch x 1/10 inch (large)

D. Identification
1. Vibratool.
2. Stamping.

E. Heat Treatment
1. 1742 F, 24 hr, water quench.
2. 1022 F, 24 hr, furnace cool.

F. Post-Test Cleaning
1. Rinse.
2. Scrub.

G. Position
1. First and second strips.
2. Third and fourth strips.

Any discussion of this article not published above will appear in June, 1961 issue.

Directory of NACE Regional and Sectional Officers

CANADIAN REGION

T. R. B. Watson, Director; Corrosion Service Ltd., 17 Dundonald St., Toronto 5, Ontario, Canada

John R. Grey, Chairman; Gas Distribution Dept., B. C. Electric Co., 3725 Lougheed Highway, Burnaby 2, B. C.

H. H. Yates, Vice Chairman; Physical Science Centre, McGill University, Montreal 2, Quebec

D. S. McIntosh, Secretary-Treasurer; Britamoil Pipe Line Co., P. O. Box 130, Calgary, Alberta

H. A. Webster, Membership Chairman; Corrosion Service, Ltd., 17 Dundonald St., Toronto 5, Ontario

• Calgary Section

G. G. Mainland, Chairman; Imperial Oil Limited, 300-9th Avenue West, Calgary, Alberta, Canada

S. N. Gell, Secretary-Treasurer; Canadian Western Natural Gas Co., Ltd., 140-6th Avenue West, Calgary, Alberta, Canada

D. S. McIntosh, Trustee; Britamoil Pipe Line Co., P. O. Box 130, Calgary, Alberta, Canada

• Edmonton Section

John L. Gattenmeyer, Chairman; Canadian Protective Coatings, Ltd., 9420 91st Street, Edmonton, Alberta

David A. Hindley, Vice Chairman; Rice Engineering and Operating, Ltd., 10509 81st Ave., Edmonton, Alberta

Hugh Slater, Secretary-Treasurer; Texaco Exploration Co., Ltd., Pipe Line Dept., 8221 109th St., Edmonton, Alberta

Malcolm W. Clarke, Trustee; Canadian Protective Coatings, Ltd., 9420 91st Street, Edmonton, Alberta

• Hamilton-Niagara Section

L. E. Sterne, Chairman; Gaco Products, Ltd., P. O. Box 132, Brantford, Ontario

C. Bullick, Vice Chairman; Imperial Oil, Ltd., Sarina Products Pipelines, Waterdown, Ontario

J. B. Hambley, Secretary; Alchem, Ltd., Burlingyon, Ontario

R. Campbell, Treasurer; Interprovincial Corrosion Control Co., Ltd., P. O. Box 167, Burlington, Ontario

• Montreal Section

Walter A. Mueller, Chairman; Pulp & Paper Res. Inst. of Canada, 3420 University St., Montreal, Quebec

Norman D. Woollings, Secretary-Treasurer; Alchem, Ltd., 65 Donegani Ave., Pointe Claire, Quebec

• Toronto Section

F. Farrer, Chairman; Trans-Northern Pipe Line Co., 696 Yonge St., Toronto, Ontario, Canada

K. G. Dellenbach, Vice Chairman; Sarnia Products Pipe Line, Waterdown, Ontario, Canada

J. Balmer, Secretary; Consumers' Gas Co., 36 Mutual St., Toronto, Ontario, Canada

D. J. Cowan, Treasurer; Corrosion Service Ltd., 17 Dundonald St., Toronto, Ontario, Canada

• Vancouver Section

John S. Whitton, Chairman; Swanson, Wright & Co., Engineers Ltd., 2210 West 12th Ave., Vancouver 9, B. C.

David M. Allan, Vice Chairman; Trans Mountain Oil Pipe Line Co. Ltd., 400 East Broadway, Vancouver 10, B. C.

Gerald B. G. Ross, Secretary; 898 River Drive, Richmond, B. C.

Robert O'Shaugnessy, Treasurer; B. C. Electric Co. Ltd., 3725 Lougheed St., Burnaby, B. C.

B. H. Levelton, Trustee; B. C. Research Council, University of B. C., Vancouver 8, B. C., Canada

NORTH CENTRAL REGION

E. F. Moorman, Director; International Harvester Company, Engineering Materials Research 7 South 600 County Line Road, Hinsdale, Illinois

A. McConnell, Chairman; George J. Meyer Mfg. Co., Meyer Pl & Dumore Court, Cudahy, Wis.

C. W. Ambler, Jr., Vice Chairman; American Zinc, Lead & Smelting Co., P. O. Box 495, East St. Louis, Ill.

L. W. Gleekman, Secretary-Treasurer; Wyandotte Chemicals Corp., Engineering Dept., 1609 Biddle Ave., Wyandotte, Mich.

• Chicago Section

Daniel G. Keefe, Chairman; Swift & Company, Union Stock Yards, Chicago 9, Ill.

Wayne H. Schultz, Vice Chairman; Dearborn Chemical Co., 375 Merchandise Mart, Chicago 54, Illinois.

David B. Sheldahl, Secretary; Sinclair Research Laboratories, Inc., 400 East Sibley Blvd., Harvey, Ill.

L. LeRoy Swan, Treasurer; Illinois Bell Telephone Company, 208 W. Washington St., Chicago 6, Ill.

Ivan J. Acosta, Trustee; Crane Company, 4100 S. Kedzie Ave., Chicago, Ill.

• Cleveland Section

John Scott, Chairman; Truscon Laboratories, 1372 Primrose Drive, Mentor, Ohio

Peter P. Skule, Vice Chairman; East Ohio Gas Co., 1717 East Ninth St., Cleveland 14, Ohio

W. H. Hooker, Secretary-Treasurer; Harco Corporation, 4600 East 71 St., Cleveland 25, Ohio

J. F. Bosich, Trustee; Diamond Alkali Co., P. O. Box 430, Painesville, Ohio

• Detroit Section

Euel Vines, Chairman; Koppers Company, 301 West Eight Mile Road, Detroit 3, Mich.

Carl Durbin, Vice Chairman; Chrysler Corp., P. O. Box 1118, Detroit 31, Mich.

Leonard Rowe, Treasurer; General Motors Corp., 12 Mile and Mound Roads, Warren, Mich.

James Everett, Secretary; Truscon Labs., Box 69, Milwaukee Junc. P. O., Detroit 11, Mich.

David Hill, Trustee; Timken Detroit Axel Co., 100-400 Clark Ave., Detroit, Mich.

• Eastern Wisconsin Section

Dave Walczyk, Chairman; A. O. Smith Corp., Dept. 9753, P. O. Box 584, Milwaukee 1, Wis.

Thomas Quick, Vice Chairman; 806 Third St., West De Pere, Wis.

Harold F. Haase, Secretary-Treasurer; Consultant, 2202 South 28th St., Milwaukee 15, Wis.

David Walczak, Trustee; A. O. Smith Corp., Dept. 9753, P. O. Box 584, Milwaukee 1, Wisconsin

• Greater St. Louis Section

E. Gent Johannes, Chairman; Mineral Products Co., 1834 Gravois Ave., St. Louis 4, Mo.

A. Orman Fisher, Vice Chairman; Engineering Dept., Monsanto Chemical Co., 800 North Lindberg Blvd., St. Louis 24, Mo.

J. W. Cushing, Secretary; Carboline Co., 32 Hanley Ind. Ct., St. Louis 17, Mo.

M. S. VanDevanter, Treasurer; VanDevanter Engineering, Inc., 2207 Pine St., St. Louis, Mo.

A. Orman Fisher, Trustee; Engineering Dept., Monsanto Chemical Co., 800 North Lindbergh, St. Louis 24, Missouri

• Kansas City Section

Dan R. Werner, Chairman; American Tel. & Tel. Co., 811 Main St., Room 850, Kansas City, Mo.

Hobart Shields, Vice Chairman; Standard Oil Co., (Ind.), Sugar Creek, Mo.

O. E. Moore, Secretary-Treasurer; Panhandle Eastern Pipe Line Co., 1221 Baltimore Ave., Kansas City, Mo.

Jack L. Grady, Trustee; J. L. Grady Company, Box 9484, Kansas City 33, Mo.

• Southwestern Ohio Section

Sylvan Falck, Chairman; Inner-Tank Lining Corp., 4777 Eastern Ave., Cincinnati 26, Ohio

Eugene E. Haney, Vice Chairman; Armco Steel Corp., 703 Curtis, Middletown, Ohio

Arthur D. Caster, Treasurer; 2864 McFarlan Park Dr., Cincinnati 11, Ohio

S. Clifford Jones, Secretary; Cin. Gas & Elec. Co., P. O. Box 960, Cincinnati 1, Ohio

• Twin Cities Section

C. C. Van Rickley, Chairman; Route 3, Box 225, Excelsior, Minn.

E. G. Albrecht, Vice Chairman; Northwestern Bell Telephone Co., 224 South 5th St., Minneapolis 2, Minn.

J. F. Williams, Secretary-Treasurer; Northern States Power Co., 1518 Chestnut Ave. North, Minneapolis 3, Minn.

C. M. Jacobson, Trustee; Minnesota Mining and Manufacturing Co., 900 Bush Ave., St. Paul 6, Minn.

NORTHEAST REGION

J. Dwight Bird, Director; Dampney Co., 50 Business St., Hyde Park, Boston 36, Mass.

A. F. Minor, Chairman; American Tel. & Tel. Co., 195 Broadway, New York 17, N. Y.

J. H. Cogshall, Vice Chairman; Pennsalt Chemicals Corp., Corrosion Engineering Products Dept., Natrona, Pa.

J. M. Bialosky, Secretary-Treasurer; Koppers Co., Inc., Verona Research Venter, Box 128, Verona, Pa.

• Baltimore-Washington Section

Herbert F. Lewis, Chairman; Southern Galvanizing Co., 1620 Bush St., Baltimore 30, Md.

Neil B. Garlock, Vice Chairman; 1500 Rhode Island Ave., N. W., Washington 5, D. C.

Thomas E. Krehnbrink, Secretary-Treasurer; 1334 Winston Rd., Baltimore 12, Md.

• Central New York Section

Gordon R. Watt, Chairman; James Watt, Inc., 111 Teale Ave., Syracuse 3, N. Y.

James M. Fitzsimmons, Secretary-Treasurer; Niagara Mohawk Power Corp., 300 Erie Blvd., West, Syracuse 2, N. Y.

• Genesee Valley Section

E. Grant Pike, Chairman; 463 Helendale Rd., Rochester 9, N. Y.

Richard H. Saunders, Vice Chairman; Rochester Gas & Electric Corp., 89 East Ave., Rochester, N. Y.

Robert M. White, Secretary-Treasurer; Eastman Kodak Co., Engineering Div., Metal Lab., Kodak Park Works, Rochester, N. Y.

• Greater Boston Section

L. Malcolm Mosher, Chairman; Bethlehem Steel Corp., Quincy 69, Mass.

W. S. Sanders, Vice Chairman; Algonquin Gas Transmission Co., 25 Faneuil Hall Square, Boston 9, Mass.

Manson Glover, Secretary-Treasurer; Glover Coating Co., 215 Pleasant St., Stoughton, Mass.

• Kanawha Valley Section

Kenneth R. Gosnell, Chairman; Dev. Dept., Union Carbide Chemical Co., South Charleston, W. Va.

William R. Lambert, Vice Chairman; Production Dept., United Fuel Gas Co., Box 1273, Charleston, W. Va.

James A. Parker, Treasurer; United Fuel Gas Co., Box 1273, Charleston 25, W. Va.

Charles C. Stoneking, Secretary; Hope Natural Gas Co., Engineering Dept., 445 West Main St., Clarksburg, W. Va.

J. M. Bates, Trustee; Union Carbide Chemicals Co., P. O. Box 8361, South Charleston, W. Va.

• Lehigh Valley Section

Seymour Charles Frye, Chairman; Bethlehem Steel Co., Bethlehem, Pa.

Ray Graver, Vice Chairman; Electro Chemical Eng. & Mfg. Co., 750 Broad St., Emmaus, Pa.

Donald H. Gittelman, Secretary-Treasurer; The Glidden Co., 3rd & Bern Sts., Reading, Pa.

William H. Rutter, Member at Large; Electro Chemical Eng. & Mfg. Co., 750 Broad St., Emmaus, Pa.

• Metropolitan New York Section

Benton C. Lattin, Chairman; Ebasco Services, Inc., 2 Rector St., New York 6, N. Y.

Stephen N. Palica, Vice Chairman; Consolidated Edison Co. of N. Y., 9 South First Ave., Mt. Vernon, N. Y.

Russell E. Gackenbach, Secretary-Treasurer; American Cyanamid Co., 30 Rockefeller Plaza, New York 20, N. Y.

Directory of NACE Regional and Sectional Officers

• Niagara Frontier Section

E. K. Benson, Chairman; New York Telephone Co., 28 Church St., Buffalo 2, N. Y.

C. R. Bishop, Vice Chairman; Metals Research Labs., Union Carbide Metals Co., P. O. Box 580, Niagara Falls, N. Y.

R. E. Robinson, Secretary-Treasurer; Hooker Chemical Corp., Niagara Falls, N. Y.

• Philadelphia Section

E. D. Bossert, Chairman; 190 South Trooper Road, Norristown, Pa.

D. F. Woolley, Jr., Vice Chairman; 303 Landsende Rd., Devon, Pa.

R. K. Kichline, Secretary-Treasurer; Duriron Co., Inc., 3 Penn Center Plaza, Philadelphia 2, Pa.

• Pittsburgh Section

J. B. Vrable, Chairman; New York State Natural Gas Corp., 2 Gateway Center, Pittsburgh 22, Pa.

William L. Mathay, Vice Chairman; United States Steel Corp., Applied Research Lab., P. O. Box 38, Monroeville, Pa.

Raymond C. Bowden, Secretary; Natl. Tube Div. U. S. Steel Corp., P. O. Box 266, Pittsburgh 30, Pa.

John D. Keane, Treasurer; Steel Structures Painting Council, 4400 5th Ave., Pittsburgh 13, Pa.

• Schenectady-Albany-Troy Section

J. F. Quinlan, Chairman; Material & Process Laboratory, General Electric Co., Schenectady, N. Y.

H. Suss, Vice Chairman; Knolls Atomic Power Laboratory, General Electric Co., Schenectady, N. Y.

J. A. McGowan, Secretary-Treasurer; Alco Products, Inc., Schenectady, N. Y.

• Southern New England Section

William W. Steinert, Chairman; A. V. Smith Engineering Co., 119 Ann St., Hartford 3, Conn.

Ralph O. Lewis, Sr., Vice Chairman; Charles Pfizer Co., Inc., Groton, Conn.

Arthur Tuthill, Secretary-Treasurer; International Nickel Co., 75 Pearl St., Hartford, Conn.

• Wilmington Section

James M. Brady, Chairman; 1217 Newport Pike, Woodcrest, Wilmington 177, Del.

Louis M. Nieliwocki, Vice Chairman; 1510 Stoney Rum Dr., Northwood, Wilmington 3, Del.

K. L. Moore, Secretary-Treasurer; Tidewater Oil Co., Delaware City, Del.

SOUTHEAST REGION

Arthur B. Smith, Director; Amercoat Corp., P. O. Box 2977, Jacksonville, Fla.

George M. Jeffares, Chairman; Plantation Pipe Line Co., P. O. Box 1743, Atlanta 1, Ga.

Henry T. Rudolf, Vice Chairman; Atlantic Coatings Co., Inc.; Box 2976, Jacksonville 3, Fla.

James L. English, Secretary-Treasurer; 223 Virginia Road, Oak Ridge, Tenn.

Edwin J. Tilton, Jr., Assistant Secretary-Treasurer; Florida Power & Light Co., Box 3100, Miami 30, Fla.

• Atlanta Section

James P. McArdle, Jr., Chairman; American Tel. & Tel. Co., 917 Hurt Bldg., Atlanta, Ga.

James M. Joyner, Secretary-Treasurer; Transmission & Protection Group, Sou. Bell Tel. & Tel. Co., 795 Peachtree St., N. E. Atlanta, Ga.

James R. Stem, Asst. Secretary-Treasurer, 2141 McKinley Rd., N. W., Atlanta 18, Ga.

• Birmingham Section

John P. Paisley, Jr., Chairman; American Tel. & Tel. Co., 1534 Brown Marx Bldg., Birmingham, Ala.

Marion M. Fink, Vice Chairman; Tennessee Coal & Iron Division, U. S. Steel Corp., Electrical Lab., P. O. Box 599, Fairfield, Ala.

James C. Ray, Secretary-Treasurer; Southern Bell Tel. & Tel. Co., P. O. Box 2662, Birmingham 2, Ala.

Douglas D. Holmes, Assistant Secretary-Treasurer; Alabama Power Co., Box 2641, Birmingham 2, Ala.

• Carolinas Section

Ray G. Penrose, Chairman; Aluminum Co. of America, 1000 Wachovia Bank Bldg., Charlotte, N. C.

Robert H. Gardner, Jr., Vice Chairman; Koppers Co., Inc., Tar Products Div., P. O. Box 1688, Charlotte, N. C.

David B. Anderson, Secretary-Treasurer; International Nickel Co., Inc., P. O. Box 262, Wrightsville Beach, N. C.

• East Tennessee Section

James A. McLaren, Chairman; Oak Ridge National Laboratory, Div. of Union Carbide Corp., P. O. Box P, Oak Ridge, Tennessee

Frank A. Knox, Sec.-Treas.; Oak Ridge National Laboratories, UCNC, Building 4501, X-10, Oak Ridge, Tenn.

• Jacksonville (Fla.) Section

Henry T. Rudolph, Chairman; Atlantic Coatings Co., P. O. Box 2976, Jacksonville 3, Fla.

Herman D. Collete, Jr., Vice Chairman; Division Engineering, Florida Power & Light Co., Daytona Beach, Fla.

Ernest E. Sandberg, Secretary-Treasurer; 10567 Serena Dr., Jacksonville 11, Fla.

• Miami Section

Newt Bollinger, Chairman; Peoples Gas Co., P. O. Box 1107, North Miami, Fla.

Charles H. A. Montague, Vice Chairman; Peoples Gas System, East Coast Div., 564 N. E. 125th St., North Miami, Fla.

James J. Abril, Secretary-Treasurer; Florida Power & Light Co., P. O. Box 3100, Miami, Fla.

• Ohio Valley Section

John S. Heintzman, Chairman; Southern Bell Tel. & Tel. Co., Room 404, 534 Armory Place, Louisville, Ky.

Lewis P. Aker, Vice Chairman; Louisville Gas & Electric Co., P. O. Box 354, Louisville, Ky.

C. Norman Beck, Secretary-Treasurer; Louisville Gas & Electric Company, P. O. Box 354, Louisville 3, Ky.

• Tidewater Section

Murray S. Spicer, Chairman; Chesapeake & Potomac Tel. Co. of Virginia, 703 East Grace St., Richmond 19, Va.

Otis J. Streever, Vice Chairman; 124 Parkway Dr., Warwick, Va.

John W. Berryman, Jr., Secretary-Treasurer; 3463 Fletcher Dr., Norfolk 13, Va.

SOUTH CENTRAL REGION

H. E. Waldrip, Trustee-at-Large; Gulf Oil Corp., 5311 Kirby Drive, Houston, Texas

J. A. Caldwell, Director; Humble Oil & Refining Co., P. O. Box 2180, Houston, Texas

Wm. F. Levert, Chairman; United Gas Pipe Line Co., P. O. Box 1407, Shreveport, La.

Dan H. Carpenter, Vice Chairman; 503 Liberty Bank Bldg., Oklahoma City 2, Okla.

Carl M. Thorn, Secretary-Treasurer; Southwestern Bell Telephone Co., P. O. Box 2540, San Antonio, Texas

W. C. Koger, Ass't Secretary-Treasurer; Cities Service Oil Co., Cities Service Bldg., Bartlesville, Okla.

• Alamo Section

J. C. Kneuper, Chairman; City Public Service Board, Gas Dept., P. O. Box 1771, San Antonio, Texas

R. N. Dobie, Vice Chairman City Public Service Board, 511 S. Salado St., San Antonio, Texas

J. W. Gibson, Secretary-Treasurer; D. W. Haering and Co., Inc., P. O. Box 10337, San Antonio, Texas

Max F. Schlather, Trustee; United Gas Pipe Line Co., P. O. Box 421, San Antonio, Tex.

• Central Oklahoma Section

Frank B. Burns, Chairman; General Asphalts, Inc., Wynnewood, Okla.

Truel E. Adams, Vice Chairman; Consolidated Gas Utilities, P. O. Box 1439, Oklahoma City, Okla.

John A. Knox, Secretary-Treasurer; Halliburton Oil Well Cementing, Duncan, Okla.

Frank Burns, Trustee; General Asphalts, Inc., P. O. Box 305, Wynnewood, Okla.

• Corpus Christi Section

Fred C. Reed, Chairman; Pipe Line Service Co., Box 578, Corpus Christi, Texas

James L. Lankford, Vice Chairman; Lankford Painting Co., Inc., Box 4009, Corpus Christi, Texas

Joseph A. Hannabass, Secretary-Treasurer; Delhi-Taylor Oil Corp., Box 4067, Corpus Christi, Texas

Paul H. Laudadio, Trustee; Briner Paint Mfg. Co., 3713 Agnes St., Corpus Christi, Texas

• East Texas Section

J. R. Mottley, Chairman; Tidewater Oil Co., Scroggins, Texas

Dick Simon, Vice Chairman; Wesco, Longview, Texas

John Luttig, Secretary; Atlantic Refining Co., Greggton, Texas

Lee Rutherford, Treasurer; Magna Chemicals, Inc., Kilgore, Texas

Jim Orchard, Trustee; Nocor Chemical Company, P. O. Box 54, Longview, Texas

• Greater Baton Rouge Area Section

W. W. Gilpin, Chairman; The "K" Way Equipment Co., P. O. Box 2922, Baton Rouge 1, La.

Arthur C. Doyle, Vice Chairman; Metal Goods Corp., P. O. Box 2361, Baton Rouge, La.

Thomas C. Robert, Secretary-Treasurer; 2855 Elgin St., Baton Rouge, La.

Donald C. Townsend, Trustee; Ethyl Corp., P. O. Box 341, Baton Rouge 1, La.

• Houston Section

C. B. Tinsley, Chairman; Southwestern Bell Telephone Co., Room 301, 1114 Texas Ave., Houston 2, Texas

O. A. Melvin, Vice-Chairman; Carboline Company, Box 14284, Houston 21, Tex.

Ben Russell, Secretary-Treasurer; Rio Engineering Co., Box 6035, Houston 6, Texas

J. T. Payton, Trustee; Texaco, Inc. Laboratory, Box 425, Bellaire, Texas

• New Orleans Section

Joe W. Redden, Chairman; Napko Corp., P. O. Box 13216, New Orleans, La.

H. R. Hanson, Vice Chairman; Humble Oil & Refining Co., Box 626, New Orleans, La.

W. B. Ackenhausen, Secretary-Treasurer; 1700 Riviere Ave., Airline Park, Metairie, La.

O. L. Grosz, Trustee; California Company, 800 California Co. Bldg., New Orleans, La.

• North Texas Section

Donald F. Taylor, Jr., Chairman; Otis Engineering Corp., P. O. Box 35206, Dallas 35, Texas

Jerry R. McIntyre, Vice Chairman; Atlantic Refining Co., P. O. Box 2819, Dallas, Texas

George F. Hunt, Secretary-Treasurer; Johns-Manville Corp., 1019 Dragon St., Dallas, Texas

Glyn W. Beesly, Trustee; Dallas Power & Light Co., 1506 Commerce St., Dallas, Tex.

• Panhandle Section

Jack R. St. Clair, Chairman; Dearborn Chemical Co., Box 23, White Deer, Texas

Jack L. Carter, Vice Chairman; Box 464, Hooker, Okla.

Thomas T. Harris, Secretary-Treasurer; Engineering Dept., Phillips Petroleum Co., Box 327, Phillips, Texas

V. R. Ogilvie, Trustee; Plas-Tex Co., Borger, Texas

• Permian Basin Section

G. K. Harding, Chairman; Gulf Oil Corp., Star Route 1, Crane, Texas

Robert C. Booth, 1st Vice Chairman; Plastic Applicators, Inc., Box 2749, Odessa Texas

Robert F. Weeter, 2nd Vice Chairman; Mobil Oil Co., Box 3115, Midland, Texas

A. L. Mortimer, Secretary-Treasurer; Magna Chemical, Inc., 1420 Wilshire Dr., Odessa, Texas

Roscoe Jarmon, Trustee; Permian Enterprises, Inc., P. O. Box 4132, Odessa, Texas

• Rocky Mountain Section

B. K. Wheatlake, Chairman; Consulting Water Chemist, 1318 S. Milwaukee, Denver 10, Colo.

William P. McKinnell, Jr., Vice Chairman; Ohio Oil Co., P. O. Box 269, Littleton, Colo.

Edward L. Kent, Jr., Secretary-Treasurer; Coast Paint & Lacquer Co., 433 Franklin St., Denver 18, Colo.

Paul W. Lewis, Trustee; Bureau of Reclamation, Denver Federal Center, Denver, Colo.

• Sabine-Neches Section

Orell Tex Collins, Chairman; Nalco Chemical Co., 1450 Rikisha Lake, Beaumont, Texas

Ralph P. Gulley, Vice Chairman; Gulf Oil Corp., P. O. Box 701, Port Arthur, Texas

Hugh S. Hickerson, Jr., Secretary-Treasurer; Columbia Southern Chemical Corp., P. O. Box 1000, Lake Charles, La.

Jesse J. Baker, Trustee; Mobile Oil Co., 2950 Lucas Dr., Beaumont, Texas

• Shreveport Section

Grady Howell, Chairman; Tube-Kote Co., Shreveport, La.

D. A. Tefankjian, Secretary; Texas Eastern Transmission Corp., Shreveport, La.

Frank Therall, Treasurer; Interstate Oil Pipe Line Co., Shreveport, La.

Directory of NACE Regional and Sectional Officers

• Teche Section

Ronald J. Cernik, Chairman; Union Oil Co. of California, P. O. Box 421, Abbeville, La.

Lowell R. Pounds, Vice Chairman; Visco Products Co., 113 Marner Dr., Lafayette, La.

John R. Smith, Secretary: Tretolite Co., 300 Genevieve Dr., Lafayette, La.

Lee R. De Rouen, Treasurer; Union Oil & Gas Corp. of La., 2nd Floor Pioneer Bldg., Lake Charles, La.

Samuel E. Fairchild, Trustee; Texas Pipe Line Co., P. O. Box 1145 Oil Center Sta., Lafayette, La.

• Tulsa Section

C. O. Smith, Chairman; Humble Oil & Refining Co., Carter Div., Box 801, Tulsa 2, Okla.

Ray W. Amstutz, Vice Chairman; Earlougher Engineering Co., 3316 East 21st St., Tulsa, Okla.

Herbert M. Cooley, Secretary; Bethlehem Steel Co., 1810 So. Baltimore St., Tulsa 19, Okla.

James A. Rush, Treasurer; Nalco Chemical Co., 1311 East 38th St., Tulsa 5, Okla.

Richard E. Lembcke, Trustee; Cities Service Research & Development Co., 920 East Third St., Tulsa 20, Okla.

• West Kansas Section

Ray E. Walsh, Chairman; Atlas Powder Co., Great Bend, Kan.

Robert E. Adams, Vice Chairman; Mobil Oil Co., Great Bend, Kan.

Zane Barnett, Secretary-Treasurer; Tretolite Co., Great Bend, Kan.

Cliff Koger, Trustee, Cities Service Oil Co., Bartlesville, Okla.

WESTERN REGION

E. H. Tandy, Director; Standard Oil Company of California, P. O. Box 97, El Segundo, Cal.

A. E. Storm, Chairman; Tidewater Oil Co., Associated, Cal.

O. L. Hudrlik, Vice Chairman; Route 1, Box 329A, Molalla, Ore.

J. W. Caldwell, Secretary-Treasurer; Bunker Hill Co., 660 Market St., San Francisco 4, Cal.

• Central Arizona Section

Blair B. Emory, Chairman; Salt River Power District, P. O. Box 1980, Phoenix, Ariz.

Richard Patterson, Secretary-Treasurer; El Paso Natural Gas Co., Box 1630, Phoenix, Ariz.

George Menzler, Membership Chairman; Arizona Public Service, 501 S. 3rd Ave., Phoenix, Ariz.

• Los Angeles Section

Harry J. Kipps, Chairman; 10954 South Kane Ave., Whittier, Cal.

Philip H. Burch, Vice Chairman; Products Research Co., 2919 Empire Ave., Burbank, Cal.

Thomas J. Degnan, Secretary-Treasurer; Pacific Lighting Gas Supply Co., 810 South Flower, Los Angeles, Cal.

Carl E. Hedborg, Trustee; Research Dept., Union Oil Company of California, P. O. Box 76, Brea, Cal.

• Portland Section

John Van Bladeren, Chairman; Northwest Natural Gas Co., 132 N. W. Flanders St., Portland 9, Ore.

George K. Merz, Vice Chairman; Portland General Electric Co., 1510 S. E. Water Ave., Portland 14, Ore.

Keene R. Shogren, Secretary-Treasurer; Northwest Natural Gas Co., N. W. 2nd & Flanders Sts., Portland 9, Ore.

Rodney V. Moorman, Trustee; Bonneville Power Administration, P. O. Box 3537, Portland 8, Ore.

• Puget Sound Section

Robert T. Mercer, Chairman; 618 W. Highland Drive, Seattle 99, Wash.

Tom F. Kelly, Secretary-Treasurer; Tereco Sales Co., 13535 Monster Rd., Seattle 88, Wash.

• Salt Lake Section

Frank L. Pehrson, Chairman; Kennecott Copper Corp., Box 1650, Salt Lake City, Utah

Harry R. Brough, Vice Chairman; Mountain Fuel Supply Co., Box 989, Salt Lake City, Utah

John P. Reeves, Secretary-Treasurer; Reeves & Co., 334 West 17th South, Salt Lake City 15, Utah

• San Diego Section

Otto L. Hepner, Chairman; Alvarado Filtration Plant, La Mesa, Cal.

Albert F. Hooper, Vice Chairman; 342 Patricia Ave., Chula Vista, Cal.

Richard R. Spear, Secretary-Treasurer; The Pacific Tel. & Tel. Co., 620 "C" St., Room 206, San Diego 1, Cal.

F. O. Waters, Trustee; 6326 Montezuma Road, San Diego 15, Cal.

• San Francisco Bay Area Section

Roy O. Dean, Chairman; Pacific Gas & Electric Co., 4245 Hollis St., Emeryville 8, Cal.

Ernest F. Ehmke, Vice Chairman; Tidewater Oil Co., Associated, Cal.

Glenn P. Snarr, Secretary-Treasurer; Bunker Hill Co., 660 Market St., San Francisco 4, Cal.

• San Joaquin Valley Section

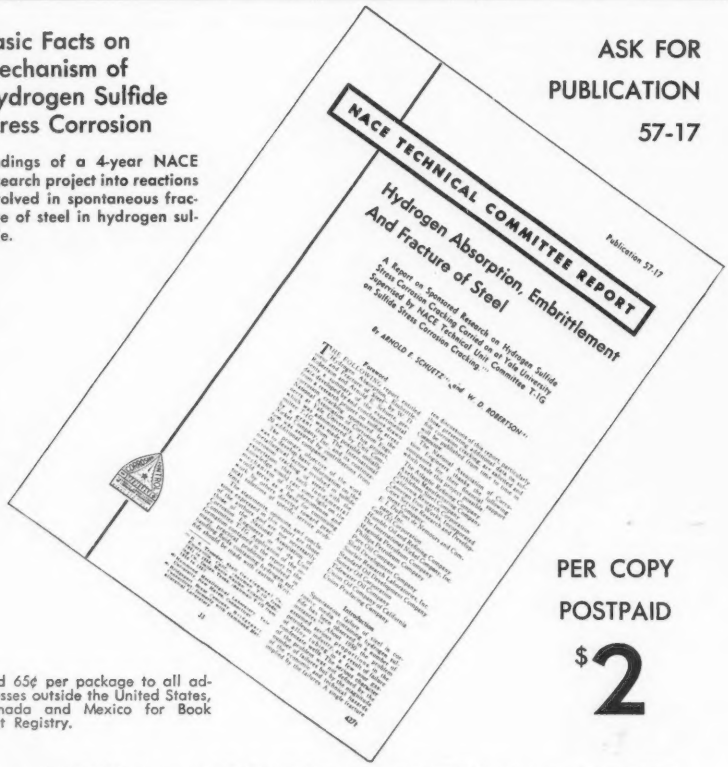
Robert M. Evans, Chairman; Standard Oil of Cal., 11-C Camp, Taft, Cal.

Bruce A. Grover, Vice Chairman; Western Gulf Oil Co., P. O. Box 1392, Bakersfield, Cal.

Nat G. Haseltine, Secretary-Treasurer; Standard Oil of Cal., Taft, Cal.

Basic Facts on Mechanism of Hydrogen Sulfide Stress Corrosion

Findings of a 4-year NACE research project into reactions involved in spontaneous fracture of steel in hydrogen sulfide.



ASK FOR PUBLICATION 57-17

PER COPY POSTPAID $2

Add 65¢ per package to all addresses outside the United States, Canada and Mexico for Book Post Registry.

NATIONAL ASSOCIATION of CORROSION ENGINEERS
1061 M & M Bldg. Houston 2, Texas

Technical Articles Scheduled for January

Effect of Various Curing Agents on Chemical Resistance of Epoxy Resins, by Ronald L. DeHoff

Inhibition of Corrosion of Commercial Aluminum Alkaline Solutions, by J. Sundarajan and T. L. Rama Char

Effect of Sodium Exposure on Mechanical Properties of Zirconium, by Jack C. Bokros

Accelerated Test Procedure for Evaluation of Fiber Reinforced Resin Equipment in the Chemical Industry, by Robert A. Cass and Otto H. Fenner

Corrosion Studies of Aluminum in Chemical Process Operation, by E. H. Cook, R. L. Horst and W. W. Binger

Corrosion Resistance of Dense, Impermeable Silicon Carbide, by Roy Dial and G. E. Mangsen

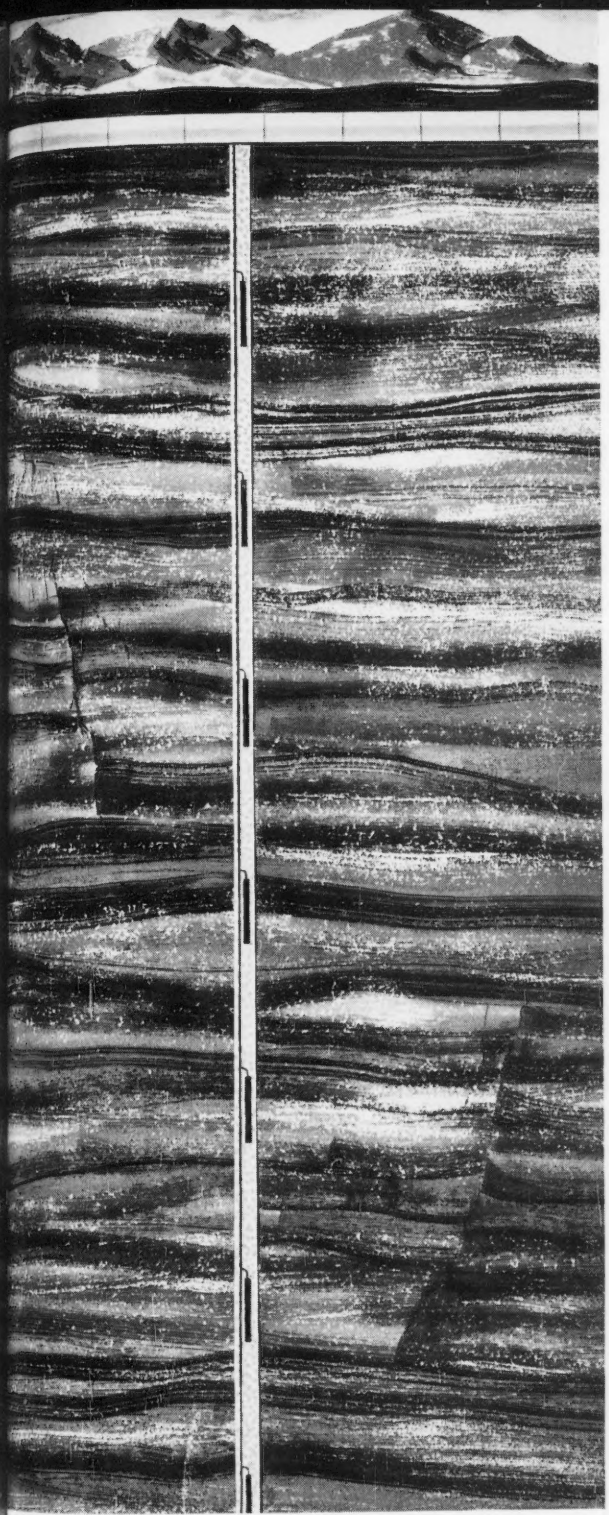
Design for Prevention of Pipe Corrosion Based on Survey of Ground Potential Distribution of the Planned Route, by Shigeo Fukata and Shigeki Sekimto

Characteristics of Asphalt Mastic Coatings, by Lyle R. Sheppard

Corrosion-Erosion of Sensitized AISI Type 304 Stainless Steel in a Thorium Dioxide-Uranium Trioxide Slurry, by Donald C. Vreeland

SYMPOSIUM: Methods and Experiences in Underground Cathodic Protection

1. Methods and Experiences of Ohio Bell Telephone Company in Cleveland With Cathodic Protection of Underground Cables, by Oliver Henderson
2. Methods and Experiences in Underground Protection, by P. P. Skule
3. Methods and Experiences in Underground Cathodic Protection, by L. H. West



for "deep well"
installation, specify

Duriron®
impressed current
Anodes

Durco high silicon iron alloys (Duriron, Durichlor, and D-51) are being used almost exclusively for new deep well anode installations.

Durco anodes combine the advantages of:

1 PERMANENCY *(Weight loss 1/20 of that of steel)*

2 EASE OF INSTALLATION *(Bulk volume of scrap steel is avoided)*

3 MINIMUM TOTAL COST *(No backfill or pre-packing of anodes required)*

Durco high silicon iron alloys are resistant to sea, brackish, and fresh waters, as well as all soil environments. Complete details are contained in Bulletin DA/6.

THE DURIRON COMPANY, INC.
DAYTON, OHIO

DURCO
CORROSION RESISTING ALLOYS & EQUIPMENT

CORBAN

inhibitor squeeze—
effective, economical way
to combat well corrosion

The "squeeze" method of applying Corban®—Dowell's family of corrosion inhibitors—is continuing to set new records for long-term corrosion protection in oil and gas wells.

"Squeezing" a well with Corban involves the pumping of inhibitor through the tubing string into the producing formation. The tubing and other metal parts contacted by the Corban, receive a protective film of inhibitor. As the well is produced, Corban from the formation maintains this protective film for an extended period.

The inhibitor squeeze method was first used to combat corrosion in Louisiana and East Texas wells which were difficult to treat conventionally.

One of the first wells squeezed with Corban was a gas distillate well on the Louisiana Gulf Coast in June of 1956. Since then, this well has been squeezed with Corban four times. A recent caliper survey was compared with one made prior to the first squeeze. The comparison showed that no noticeable corrosion had occurred during that three-year period. No down-hole equipment had been replaced on this well during this time. Other wells in this area, treated with different methods, had required some replacement of tubing due to corrosion.

Get an engineered recommendation on the use of Corban in your wells from your nearest Dowell office or station. Or write Dowell, Tulsa 1, Oklahoma.

Products for the oil industry

DIVISION OF THE DOW CHEMICAL COMPANY

DOWELL